PUBLIC NOTICE

Tennessee Valley Authority (TVA) has applied to the Tennessee Department of Environment & Conservation, Division of Air Pollution Control for approval to construct and operate a cogeneration site at the Johnsonville Fossil Plant. The cogeneration site will consist of one existing combustion turbine (CT), one heat recovery steam generator (HRSG), and two auxiliary boilers. The project is subject to review under the State rule for Prevention of Significant Deterioration of Air Quality (PSD), Paragraph 1200-03-09-.01(4) of the Tennessee Air Pollution Control Regulations, which requires a public notification and thirty (30) day public comment period.

The Division of Air Pollution Control has reviewed the application with respect to the above-mentioned PSD regulations and has determined that construction can be approved if certain conditions are met. A copy of the PSD application materials, a copy of the PSD preliminary determination, and a copy of the draft construction permit are available for public inspection during normal business hours at the following locations:

Humphreys County Public Library 201 Pavo Avenue Waverly, TN 37185	and	Tennessee Department of Environment and Conservation Division of Air Pollution Control William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, Tennessee 37243

Electronic copies of the draft permit and supporting materials are available by accessing the TDEC internet site located at:

http://www.tn.gov/environment/topic/ppo-air

Interested parties are invited to review these materials and comment on the proposed modifications.

The Division of Air Pollution Control will hold a public hearing on April 15, 2016, to accept written or oral comments on the proposed project. The public hearing will be held at 6:00 PM Central Time on Friday, April 15, 2016, at Johnsonville State Historic Park, 90 Nell Beard Road, New Johnsonville Tennessee. Written comments will be accepted until the end of the public hearing. Comments should be addressed to **Director, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 15th Floor, Nashville, Tennessee 37243.** Written comments may also be submitted electronically to air.pollution.control@tn.gov. A final determination will be made after consideration of all relevant comments and other available information. Questions concerning the source may be addressed to Mr. Travis Blake at the address shown above, or by calling (615) 532-0554 or (615) 532-0617.

Individuals with disabilities who wish to review information maintained at the above-mentioned depositories should contact the Tennessee Department of Environment and Conservation to discuss any auxiliary aids or services needed to facilitate such review. Such contact may be in person, by writing, telephone, or other means, and should be made no less than ten days prior to the end of the public comment period to allow time to provide such aid or services. Contact the Tennessee Department of Environment and Conservation ADA Coordinator, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 2nd Floor, Nashville, TN 37243, 1-(866)-253-5827. Hearing impaired callers may use the Tennessee Relay Service, 1-(800)-848-0298.

(Publish only the text which appears above this line)

For the Humphreys County "News Democrat" – publish once on March 16, 2016.

Air Pollution Control DATE: March 4, 2016

Assigned to – Travis Blake

No alterations to the above are allowed:
TVA must pay for publication of this notice in the newspaper shown.

The Division of Air Pollution Control must be furnished with an affidavit from the newspaper stating that the ad was run and the date of the ad or one complete sheet from the newspaper showing this advertisement, the name of the newspaper and the date of publication. Mail to Travis Blake, Division of Air Pollution Control, William R. Snodgrass Tennessee Tower, 312 Rosa L. Parks Avenue 15th Floor, Nashville, Tennessee 37243.

PREVENTION OF SIGNIFICANT DETERIORATION
PRECONSTRUCTION REVIEW AND PRELIMINARY DETERMINATION
FOR TENNESSEE VALLEY AUTHORITY
JOHNSONVILLE COGENERATION PLANT
IN HUMPHREYS COUNTY, TENNESSEE

This review was performed by the Tennessee Air Pollution Control Division in accordance with the Rules for Prevention of Significant Deterioration.

March 16, 2016

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I. Rule Background

On June 3, 1981, the State of Tennessee adopted Tennessee Air Pollution Control Regulations (TAPCR) Rule 1200-03-09-.01(4), Prevention of Significant Air Quality Deterioration. This Rule has been subsequently amended, with the latest amendments effective November 27, 2011. Under these regulations, a source that is included in one of 28 source categories and has the potential or increased potential to emit 100 tons per year (TPY) or more of any air pollutant regulated in the Clean Air Act must be reviewed with regard to significant deterioration prior to construction. In addition, any source having the potential or increased potential to emit 250 tons per year or more of any of these air pollutants must be reviewed with the same regard.

In order to comply with the amended PSD regulations, a source with potential emissions greater than significant amounts of a regulated pollutant must meet several criteria. The first criterion is that Best Available Control Technology (BACT) must be applied to all emission points for the applicable PSD pollutant. The second criterion is that the proposed source or modification must not cause or contribute to any violation of the National Ambient Air Quality Standards (NAAQS – see **Table 1**). Finally, increases in ambient concentrations of sulfur dioxide, nitrogen dioxide and particulate matter resulting from emissions discharged by the proposed source must not exceed the increments specified by the PSD regulations (**Table 2**).

Table 1: National Ambient Air Quality Standards

Pollutant		Averaging Period	Standard
Particulate Matter	(PM_{10})	24-hour	150 µg/m^3
	($PM_{2.5}$)	Annual	15 µg/m^3
		24-hour	35 µg/m^3
Nitrogen Dioxide (NO_2)		Annual (primary and secondary)	53 ppb
		1-hour (primary)	100 ppb
Carbon Monoxide (CO)		8-hour	9 ppm
		1-hour	35 ppm
Sulfur Dioxide (SO_2)		1-hour(primary)	75 ppb
		3-hour (secondary)	0.5 ppm
Lead		3-month (primary and secondary)	0.15 µg/m^3
Ozone		8-hour (primary and secondary)	0.075 ppm

Table 2: Maximum Allowable Increases (μg/m^3) for Class II Areas	
Pollutant	**μg/m^3**
PM_{10}, annual arithmetic mean	17
PM_{10}, 24-hour maximum	30
$PM_{2.5}$, annual arithmetic mean	4
$PM_{2.5}$, 24-hour maximum	9
Sulfur dioxide: Annual arithmetic mean	20
Sulfur dioxide: 24-hour maximum	91
Sulfur dioxide: 3-hour maximum	512
Nitrogen dioxide: Annual arithmetic mean	25

II. Project Background and Description

The Tennessee Valley Authority (TVA) proposes to construct and operate a cogeneration site at the Johnsonville Fossil Plant (JOF). The cogeneration site (Johnsonville Cogeneration [JOC]) will consist of one existing combustion turbine (CT), one heat recovery steam generator (HRSG), and two auxiliary boilers.

In addition to generating electricity from the existing CT, the cogeneration site will supply steam to an off-site customer located adjacent to the JOF property. The cogeneration site will replace steam generation currently produced by four existing JOF coal-fired boiler units, which are scheduled to be retired by December 31, 2017 as required under the 2011 Federal Facilities Compliance Agreement (FFCA) and the Consent Decree. Under the terms of the FFCA and the Consent Decree requirements, emissions from the retirement of the coal-fired units may not be used for netting purposes to offset emissions from the proposed cogeneration project. Although actual emissions will decrease, estimated emissions from the proposed project will result in a significant increase in emissions and is subject to a PSD review.

The proposed modification would consist of one existing, dual-fuel combustion turbine (CT) generator, one new heat recovery steam generator (HRSG) with a duct burner, catalytic oxidation, and selective catalytic reduction (SCR); and two new natural gas-fired auxiliary boilers with low-NO_X burners, flue-gas recirculation, and SCR. In addition to these major-equipment systems, the proposed project will include one aqueous ammonia tank and instrumentation and control systems.

This proposed modification will result in significant net emissions increases for particulate matter (PM, PM_{10}, and $PM_{2.5}$), carbon monoxide (CO), nitrogen oxides (NO_X), and greenhouse gases (CO_2e). The project is therefore subject to review under the regulations governing the Prevention of Significant Air Quality Deterioration (PSD).

III. Information Used in Analysis

The applicant provided the following information in their permit application (Appendix B). The proposed modification will affect the emission sources listed in **Table 3**:

Table 3: Source Description			
Emission Source	**Stack ID**	**Description**	**Stack/Emission Point Information**
43-0011-35	EU-26	Existing combustion turbine CT-20 with new heat recovery steam generator and duct burner.	Stack Height: 150 ft Stack Diameter: 15.5 ft Exit Velocity: 61.1 ft/sec Exit Gas Temperature: 193° F
43-0011-36	EU-37	Natural gas-fired auxiliary boiler, 432 MMBtu/hr heat input capacity	Stack parameters are identical for EU-37 and EU-38. Stack Height: 199 ft Stack Diameter: 6.5 ft Exit Velocity: 59.7 ft/sec Exit Gas Temperature: 250° F
43-0011-37	EU-38	Natural gas-fired auxiliary boiler, 432 MMBtu/hr heat input capacity	

IV. Emissions Analysis

Projected emissions increases from the proposed modification (**Table 4**) were obtained from the information and assumptions given in the permit application.

Table 4: Projected Emissions Increases			
Pollutant	**Project Emissions Increase (tons/year)**	**PSD Significance Threshold (tons/year)**	**Subject to PSD Review?**
CO	318	100	Yes
NO_X	49.2	40	Yes
SO_2	12.4	40	No
PM (TSP)	30.3	25	Yes
PM_{10}	30.3	15	Yes
$PM_{2.5}$	30.3	10	Yes
VOC	28.4	40	No
Lead	0.00574	0.6	No
Sulfuric Acid Mist	0.0782	7	No
CO_2e	616,516	75,000	Yes

V. Control Technology Review

V.1. New Source Performance Standards (NSPS)

Combustion Turbine and Duct Burner

The New Source Performance Standards (NSPS) are national emission standards that apply to specific categories of new sources. As stated in the CAA Amendments of 1977, these standards "shall reflect the degree of emission limitation and the percentage reduction achievable through application of the best technological system of continuous emission reduction the Administrator determines has been adequately demonstrated."

According to the NSPS definition (40 CFR 60.14), CT-20 will be a modified source because the proposed HRSG and duct burner will result in the increase of an existing source's regulated-pollutant emission rate. Emissions from the modified CT and the new HRSG and duct burner are regulated by 40 CFR Part 60, Subpart KKKK – Standards of Performance for Stationary Gas Turbines (July 2014).

Subpart KKKK limits combustion turbine NO_X emissions to the following:

- Natural gas: 15 parts per million (ppm) corrected to 15 percent oxygen.
- No. 2 fuel oil: 42 ppm corrected to 15 percent oxygen.

A NO_X continuous emission monitoring system will be required on the HRSG stack to demonstrate that the NO_X limits are attained.

For both the CT and duct burner, SO_2 emissions are limited to using a fuel in which the potential sulfur content will not produce in excess of 0.06 pounds SO_2 per million Btu. Representative fuel sampling will be required to demonstrate that the sulfur content of the fuel does not exceed this standard.

General requirements and source-specific requirements for notification, record keeping, reporting, and performance testing are applicable and provided in 40 CFR Subpart A and Subpart KKKK, respectively. These requirements will be followed to guarantee NSPS compliance.

40 CFR 60 Subpart TTTT (Standards of Performance for Greenhouse Gas Emissions for Electric Generating Units) would not apply. The only modification to the combustion turbine would be the addition of the duct burner and HRSG for steam generation. The duct burner and HRSG supply steam to a neighboring facility but are not used to generate electricity. The portion of the source that serves a generator (combustion turbine) is not being changed.

Auxiliary Boilers

The two auxiliary boilers are required to meet 40 CFR Part 60, Subpart Db - Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (July 2014). Because both auxiliary boilers utilize pipeline-quality natural gas, they are exempt from SO_2 and PM limits and performance testing. However, SO_2 compliance is maintained through record keeping of fuel receipts provided by the supplier.

Each unit will be limited to 0.20 pound of NO_X per one million Btu of heat input. A NOX continuous monitoring system will be installed to demonstrate continuous compliance with the NOX limits.

Other NSPS requirements, such as notification, record keeping, reporting, and performance testing, are applicable and are provided in 40 CFR Subpart A and Subpart Db.

V.2. National Emission Standards for Hazardous Air Pollutants (NESHAP)

EPA has promulgated National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Hazardous Air Pollutants (HAPs) for various industrial categories. Sources in these categories that emit more than 10 tons per year of a single HAP or 25 tons per year of total HAPs are subject to major source NESHAPs. The JOC project, in conjunction with the existing JOF simple cycle combustion turbines, will have organic HAP emissions above the major threshold designation.

Combustion Turbines

40 CFR Part 63 Subpart YYYY requires affected combustion turbines to comply with a formaldehyde limit and notification requisites. Because CT-20, an existing source, will not meet the subpart's definitions of a modified source, the requirements of the Subpart YYYY are not applicable (§63.6090(b)(4)).

V.2.2 Duct Burner and Auxiliary Boilers

40 CFR Part 63 Subpart DDDDD will apply to the duct burner and the auxiliary boilers. Each is designated as a "gas 1" subcategory source (Subpart DDDDD definitions [40 CFR 63.7575]) due to their utilization of natural gas. "Gas 1" subcategory sources are not subject to emission limits but are subject to work practice standards [40 CFR 63.7500(a)(2)(e)]. The duct burner must follow the work practice standards associated with new sources that do not have an oxygen trim system; whereas, the auxiliary boiler must follow the work practice standards

associated with new sources that have an oxygen trim system. Because these sources do not have any emission limits, there are no monitoring requirements.

V.3 Best Available Control Technology (BACT) Analysis

Pursuant to TAPCR 1200-03-09-.01(4)(j), this proposed source is required to apply best available control technology (BACT) for PM, CO, NO_X, and CO_2e, since significant net emission increases are expected.

Best Available Control Technology (BACT) means an emission limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under these rules which would be emitted from any proposed new or modified air contaminant source which the Technical Secretary, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.

In no event shall application of Best Available Control Technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR part 60 or 61. If the Technical Secretary determines that technological or economic limitations on the application of measurement methodology to a particular class of sources would make the imposition of an emission standard infeasible, a design, equipment, work practice, operational standard or combination thereof, may be prescribed instead to require the application of Best Available Control Technology. Such standard shall, to the degree possible, set forth the emission reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The EPA policy memorandum dated December 1, 1987, directs applicants and permit reviewers to consider all technically feasible alternatives, including those more stringent than the BACT selection. This is referred to as the "top-down BACT analysis approach". EPA's 1990 New Source Review manual summarizes the top-down BACT analysis in the following steps:

1. Identify all control technologies.
2. Eliminate technically infeasible options.
3. Rank remaining control technologies by control effectiveness.
4. Evaluate most effective controls and document results.
5. Select BACT.

The results of the BACT analysis are summarized in **Table 5**. Top-down BACT analysis provides that all available control technologies be ranked in descending order of control effectiveness. The most effective control technology is established as BACT unless the applicant demonstrates, and the permitting authority agrees, that technical considerations, or energy, environmental, or economic impacts indicate that the most effective technology is not achievable. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.

Table 5: Summary of BACT Analysis

	Combustion Turbines & HRSG		Auxiliary Boilers	
Pollutant	**Emission Limit***	**Control Technology**	**Emission Limit***	**Control Technology**
PM, PM_{10}, $PM_{2.5}$	0.005 lb/MMBtu when burning natural gas, 0.015 lb/MMBtu when burning No. 2 oil	good combustion design and practices	0.008 lb/MMBtu	clean fuel and good combustion practices
CO	2 ppmvd when burning natural gas, 10 ppmvd when burning No. 2 oil. Both limits are corrected to 15% O_2 (30 unit-operating-day moving average)	catalytic oxidation, clean fuel, and good combustion practices	0.084 lb/MMBtu	flue gas recirculation, clean fuel, and good combustion practices
NO_X	2 ppmvd when burning natural gas, 8 ppmvd when burning No. 2 oil. Both limits are corrected to 15% O_2 (30 unit-operating-day moving average)	SCR, dry low-NO_X burners (when firing natural gas), water injection (when firing No. 2 fuel oil), clean fuel, and good combustion practices	0.013 lb/MMBtu	SCR, low-NO_X burners with flue gas recirculation, clean fuel, and good combustion practices
CO_2e	1,800 lb/MWh (12-month moving average)	low-carbon fuel and efficient combustion design and practices	117 lb/MMBtu	low-carbon fuel, efficient design (including insulation to reduce ambient heat loss), good combustion practices, and good operating and maintenance practices

* All heat input-based emission limits are based on the high heating value (HHV).

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions – Combustion Turbine and HRSG

TVA has proposed to control particulate matter (PM) emissions from the combustion turbine and heat-recovery steam generator (CT/HRSG) through the use of good combustion design and practices (such as proper fuel-air mixing, proper flame-residence time, etc.). The CT will primarily be fueled with natural gas, with ultra-low sulfur No. 2 fuel oil to be used in the unlikely event of natural gas curtailment. The proposed emission limits for filterable PM from the CT/HRSG unit are 0.005 pounds per million Btu (lb/MMBtu) when firing natural gas, and 0.015 lb/MMBtu when firing No. 2 fuel oil.

Add-on control technologies were considered to be technically infeasible for the control of PM emissions from the CT/HRSG unit, as the RACT/BACT/LAER Clearinghouse (RBLC) did not include any installation of post-combustion PM control technologies on CTs firing natural gas or ultra-low sulfur No. 2 fuel oil.

Particulate Matter ($PM/PM_{10}/PM_{2.5}$) Emissions – Auxiliary Boilers

TVA proposed to control particulate matter (PM) emissions from the auxiliary boilers through the use of clean fuel and good combustion practices (such as proper fuel-air mixing, proper flame-residence time, etc.). The boilers will be fueled exclusively with natural gas. The proposed emission limit for total PM (condensable and filterable, combined) from each of the auxiliary boilers is 0.008 lb/MMBtu heat input.

Add-on control technologies were considered to be technically infeasible for the control of PM emissions from the auxiliary boilers, as the RBLC did not include any installation of post-combustion PM control technologies on similarly-sized boilers firing natural gas.

Carbon Monoxide (CO) Emissions – Combustion Turbine and HRSG

TVA has proposed to control carbon monoxide (CO) emissions from the CT through the use of catalytic oxidation, clean fuel (natural gas or ultra-low sulfur No. 2 fuel oil), and good combustion practices. Likewise, the HRSG selected for this project is equipped with a catalytic oxidation system. The proposed emission limits for CO are 2 ppmvd corrected to 15% O_2 (based upon a 30 unit-operating-day moving average) when firing natural gas, and 10 ppmvd corrected to 15% O_2 (based upon a 15 unit-operating-day moving average) when firing No. 2 fuel oil.

The application states that according to the RBLC, the use of an oxidation catalyst, in combination with the other control technologies mentioned above, represents the most stringent technology available for control of CO emissions from CT/HRSG units. Therefore, an evaluation of the technical feasibility, environmental impacts, energy impacts, and economic impacts is not required.

Carbon Monoxide (CO) Emissions – Auxiliary Boilers

TVA reviewed two options to control carbon monoxide (CO) emissions from the natural gas-fired auxiliary boilers (**Table 6**). The top-down analysis for each option is presented below.

Table 6: Ranked BACT Options for CO

Rank	Control Option	CO Control Efficiency	CO Emissions (tons/year)
1	Oxidation Catalyst	90%	33.1
2	Good Combustion Practice	0%	331

Oxidation Catalyst – Technical Feasibility: A catalytic oxidation system (i.e., oxidation catalyst) lowers the activation energy required for oxidation of CO to CO_2 via the excess air in the boiler's exhaust. The application states that according to the RBLC, catalytic oxidation has been successfully applied to natural gas-fired auxiliary boilers of similar size[1]. Thus, catalytic oxidation was considered to be technically feasible for control of CO emissions from the auxiliary boilers.

Oxidation Catalyst – Environmental Impacts: The application states that catalytic oxidation will generate more CO_2 and will oxidize other exhaust-gas pollutants. For

1 The RBLC summary included with Appendix C of the January 26 application indicates that oxidation catalysts were used on two boilers (see RBLC ID #PA-0253) of comparable size (~350 MMBtu/hr). The CO emission limit for these boilers was 0.0192 lb/MMBtu).

example, sulfur in natural gas is oxidized to sulfur dioxide (SO_2) within the burner but is further oxidized to sulfur trioxide (SO_3) across the catalyst. The application states that SO_3 could be emitted and/or combined with water to form sulfuric acid mist (H_2SO_4) in the exhaust flue[2]. These sulfates may condense in or react with ammonia (NH_3) in the flue-gas stream to form additional PM_{10} and $PM_{2.5}$ after release to the atmosphere. Thus, an oxidation catalyst would reduce emissions of CO but could increase emissions of PM_{10} and $PM_{2.5}$.

Oxidation Catalyst – Energy impacts: The application states that each auxiliary boiler will use an induced-draft electric fan to ensure exhaust gases flow properly out of the combustion chamber, through the SCR catalyst, and out the stack. Adding an oxidation catalyst will increase the pressure drop in the exhaust pathway and raise the fan's power consumption. Use of an oxidation catalyst would result in an energy penalty of about 1,066,200 kWh/year for each boiler.

Oxidation Catalyst – Economic Impacts: The application includes capital and operating cost estimates for purchase, installation, and operation of the oxidation catalyst and associated equipment (**Tables 7 and 8**). Capital costs include the purchase and installation of the catalyst reactor and catalyst, insulation, structural steel, and instrumentation. Annual operating costs include energy costs due to performance loss; maintenance, overhead, and administrative costs; and periodic catalyst replacement costs.

Table 7: Catalytic Oxidation Capital Costs

COST COMPONENT		COSTS ($)	BASIS OF COST COMPONENT	NOTES
Direct Capital Costs				
CatOx Associated Equipment		1,323,024	for both auxiliary boilers	1
Instrumentation		230,000		1
Sales Tax		93,181	6% of Associated Equipment and Instrumentation	2
Freight		62,121	4% of Associated Equipment and Instrumentation	2
Total Direct Capital Cost	(TDCC)	1,708,326		
Total Direct Installation Costs	(TDIC)	388,256	25% of Associated Equipment and Instrumentation	1
Indirect Capital Costs				
Engineering		77,651	5% of Associated Equipment and Instrumentation	1
Contingencies		256,249	15% of TDCC	1,3
Total Indirect Capital Costs	(TInDCC)	333,900		
Total Capital Investment	(TCI)	2,430,483	TDCC + TDIC + TInDCC	

Notes:
1 Vendor data and/or engineering estimate
2 EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002; Section 1, Chapter 2
3 EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002; Section 4.2, Chapter 2

2 The maximum SO_2 emission rate reported in the application is 1.23 lb/hr. Assuming the maximum emission rate and continuous operation of the boilers (8,760 hours/year), SO_3 emissions would be 6.73 tons/year at 100% oxidation of SO_2. Actual SO_3 emissions are not known but would likely be less than this value, due to incomplete oxidation of SO_2.

Table 8: Catalytic Oxidation Annualized Costs

COST COMPONENT		COSTS ($)	BASIS OF COST COMPONENT	NOTES
Direct Annual Costs				
Operating Personnel & Supervision		0	No additional operating and supervisory labor	1
Maintenance Labor & Materials		36,457	1.5% of TCI	3
Catalyst Replacement & Disposal		264,605	5 year lifespan	1
Future Worth Factor	(FWF)	0.1739	FWF = i * { 1 / [(1 + i)^Y - 1] }	3
			i = 7%	3
			Y = 5.00	3
Annual Catalyst Replacement Cost		46,012	Catalyst Replacement & Disposal * FWF	3
Catalyst Replacement Labor		240	3 Workers * 8 Hours / Worker * $50 / Hour	1
Performance Loss		354,239		
Total Direct Annual Cost	(TDAC)	701,553		
Indirect Annual Costs				
Overhead		21,874	60% of Maintenance Labor & Materials	2
Administrative Costs		48,610	2% of TCI	2
Capital Recovery Factor	(CRF)	0.1175	CRF = i / [1 - (1 + i)^-n]	3
			i = 10%	1
			n = 20	1
Indirect Annualized Costs		285,484	CRF * TCI	3
Total Indirect Annual Cost	(TIAC)	355,968		
Total Annual Costs	(TAC)	1,057,520	TDAC + TIAC	
Incremental CO Reduction at 90% Control		2.98E+02	tons/year for both auxiliary boilers	
Cost Effectiveness ($ per ton)		3,549	Total Annualized Cost / Incremental CO Reduction	

Notes:
1 Vendor data and/or engineering estimate.
2 EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002; Section 1, Chapter 2
3 EPA Air Pollution Control Cost Manual, Sixth Edition, January 2002; Section 4.2, Chapter 2

EPA's 1990 New Source Review manual addresses cost effectiveness as follows:

> Cost effectiveness (dollars per ton of pollutant reduced) values above the levels experienced by other sources of the same type and pollutant, are taken as an indication that unusual and persuasive differences exist with respect to the source under review. In addition, where the cost of a control alternative for the specific source reviewed is within the range of normal costs for that control alternative, the alternative, in certain limited circumstances, may still be eligible for elimination. To justify elimination of an alternative on these grounds, the applicant should demonstrate to the satisfaction of the permitting agency that costs of pollutant removal for the control alternative are disproportionately high when compared to the cost of control for that particular pollutant and source in recent BACT determinations. If the circumstances of the differences are adequately documented and explained in the application and are acceptable to the reviewing agency they may provide a basis for eliminating the control alternative.

EPA's 1990 manual recommends that cost effectiveness of a control option be calculated as both average cost effectiveness (total annualized costs of control divided by annual emission reductions, or the difference between the baseline emission rate and the controlled emission rate, **Figure 1**) and incremental cost effectiveness (comparison of the costs and emissions performance level of a control option to those of the next most stringent option, **Figure 2**).

$$\text{Average cost Effectiveness (dollars per ton removed)} = \frac{\text{Control option annualized cost}}{\text{Baseline emissions rate - Control option emissions rate}}$$

Figure 1: Average Cost Effectiveness Formula

$$\text{Incremental Cost (dollars per incremental ton removed)} = \frac{\text{Total costs (annualized) of control option - Total costs (annualized) of next control option}}{\text{Next control option emission rate - Control option emissions rate}}$$

Figure 2: Incremental Cost Effectiveness Formula

Average cost effectiveness calculations for the oxidation catalyst are shown in **Table 9**.

Table 9: Cost Effectiveness Summary – Carbon Monoxide

	CO Emissions (tons/year)	Total Annualized Cost	CO Average Cost Effectiveness***
Baseline	331	$0	
Oxidation Catalyst	33.1*	$1,057,520	$3,550**

* Assuming 90% control of CO emissions, as specified in the application.

** The average cost effectiveness is slightly better ($3,371/ton) if the 0.0192 lb/MMBtu emission limit from PA-0253 is used.

*** Since only one control option was considered, the incremental cost-effectiveness was not calculated.

Oxidation Catalyst – Summary: Use of an oxidation catalyst was determined to be technically feasible but was rejected based on energy, environmental, and economic impacts.

Good Combustion Practices: TVA proposes to control carbon monoxide (CO) emissions from the natural gas-fired auxiliary boilers through the use of flue gas recirculation (FGR), clean fuel, and good combustion practices. Since this option was the next option in the list of available control technologies and since TVA proposes this option as BACT, further technical and cost analyses are not required. The proposed emission limit is 0.084 lb/MMBtu heat input[3].

3 This emission rate is approximately equal to the allowable emission rate specified in a recent PSD permit (966859F, Eastman Chemical Company, issued June 5, 2013).

Nitrogen Oxides (NO_X) Emissions – Combustion Turbine and HRSG

TVA has proposed to control nitrogen oxides (NO_X) emissions from the CT/HRSG unit through the use of selective catalytic reduction (SCR), in combination with dry low-NO_X burners (when firing natural gas), water injection (when firing No. 2 fuel oil), clean fuel (natural gas or ultra-low sulfur No. 2 fuel oil), and good combustion practices. The proposed emission limits for NO_X are 2 ppmvd corrected to 15% O_2 (based upon a 30 unit-operating-day moving average) when firing natural gas, and eight (8) ppmvd corrected to 15% O_2 (based upon a 15 unit-operating-day moving average) when firing No. 2 fuel oil.

According to the RBLC, the use of SCR, in combination with the other control technologies mentioned above, represents the most stringent technology available for control of NO_X emissions from CT/HRSG units. The application states that because the most stringent control technology is selected, an evaluation of an SCR unit's technical feasibility, environmental impacts, energy impacts, and economic impacts is not necessary.

Nitrogen Oxides (NO_X) Emissions – Auxiliary Boilers

TVA has proposed to control NO_X emissions from the natural gas-fired auxiliary boilers through the use of selective catalytic reduction (SCR), low-NO_X burners with flue gas recirculation, clean fuel, and good combustion practices. The proposed emission limit is 0.013 lb/MMBtu heat input.

The use of SCR, in combination with the other control technologies mentioned above, represents the most stringent technology available for control of NO_X emissions from the auxiliary boilers. The application states that because the most stringent control technology is selected, an evaluation of an SCR unit's technical feasibility, environmental impacts, energy impacts, and economic impacts is not necessary.

Greenhouse Gas (GHG) Emissions – Combustion Turbine and HRSG, Auxiliary Boilers

TVA has proposed to control emissions of greenhouse gases (GHG) from the CT/HRSG unit through the use of low-carbon fuel (natural gas or ultra-low sulfur No. 2 fuel oil) and efficient combustion design and practices. TVA proposed the following emission limits:

- **Combustion Turbine and HRSG:** 1,800 pounds of CO_2e per megawatt-hour of electrical generation, (based on a 12-month moving average).

- **Auxiliary Boilers:** 117 pounds of CO_2e per million Btu heat input.

The use of carbon capture and storage (CCS) was considered and was found to be technically infeasible for control of GHG emissions. The application states that TVA considered three categories of emerging CO_2 capture systems: pre-combustion, oxy-combustion, and post-combustion.

Pre-Combustion Capture: Pre-combustion capture technologies utilize oxygen indirectly to combust fuel, which generates exhaust gases with relatively high CO_2 concentrations. The pre-combustion method involves partial combustion of natural gas with oxygen to produce a synthesis gas (i.e., syngas) composed of hydrogen (H_2) and carbon monoxide (CO). The CO is reacted with steam in a catalytic reactor (water-gas-shift reaction) to yield CO_2 and additional H_2. The CO_2 is separated via a physical or chemical absorption process, resulting in a hydrogen-rich fuel.

The application states that the pre-combustion method is technically feasible[4], but construction and operation of a gasification unit would fundamentally redefine the nature of the proposed source. Therefore, this method is not considered BACT.

Oxy-Combustion: The application states that oxygen-fired combustion (i.e., oxy-combustion) method combusts natural gas using pure oxygen diluted with recycled CO2 or water (H_2O). Oxygen is typically produced using low-temperature (cryogenic) air separation. The primary products of combustion are CO_2 and H_2O. The CO_2 can be captured by condensing the water in the exhaust stream. The application states that oxy-combustion is not considered to be technically feasible because it has not been commercially demonstrated on 7EA combustion turbines. The application notes that several pilot-scale plants are proposed, including one 50 MW demonstration plant that is scheduled for startup in 2016.

Post-Combustion Capture Technologies: Post-combustion capture technologies are utilized to isolate CO_2 from the combustion exhaust gases. The combustion turbine exhaust gases consist mostly of nitrogen (N_2), CO_2, and trace impurities (e.g., CO, SO_2, PM, etc.). Separating CO_2 from this flue gas stream is challenging because CO_2 is present at dilute concentration (~5% by volume) and at low pressure (slightly above 14.7 psi), and a large volume of gas must be treated.

Chemical absorption via monoethanolamine (MEA) is currently the most common method for post-combustion CO_2 capture. MEA reacts quickly with CO_2 at low partial pressures and has been applied primarily to petroleum refining and natural gas processing. For combustion turbines, amine absorption units have been applied only to small-scale units (e.g., a 40 MW unit in Norway) or for "slipstream" tests (e.g., 28 MW from a 320 MW NCGG

4 It should be noted that pre- or post-combustion capture cannot be considered technically feasible unless the issues of CO_2 transport and storage are addressed. These issues are discussed in subsequent sections.

plant in Massachusetts). Commercial applications of amine absorption to 7EA combustion turbines do not exist; therefore, it is not considered technically feasible.

CO_2 Transport and Storage: Captured CO_2 is compressed and transported via pipeline to a suitable long-term storage site. Options considered for long-term CO_2 storage include deep-ocean/seafloor releases, mineral carbonation, and geological formations. Long-term storage involving deep ocean/seafloor releases and deep-ocean mineral carbonation storage is not deemed technically feasible control strategy due to JOC's inland location.

The application states that geological storage in basalt formations (geological formations of solidified lava), organic shale (horizontal-lying strata of clay particles), unmineable coal seams, and saline formations are currently being investigated. The U. S. Department of Energy (DOE) classifies basalt and organic shales as potential future storage until basic questions regarding geology and chemistry can be addressed.

The application states that unmineable coal seams (e.g., seams too deep, too thin, or lacking continuity to be economically mined) may have potential for CO_2 storage. Research in unmineable coal-seam storage is ongoing, but this technology has not been demonstrated. Therefore, it is not considered technically feasible.

The application states that saline formations (brine-saturated layers of permeable sedimentary rock) offer the greatest potential for immediate storage of CO_2, because saline formations are more common than coal seams or oil and gas bearing rock. However, CO_2 storage in saline formations has not been demonstrated, and the technology is not considered technically feasible.

The application states that geological formations that harbor oil and gas reserves are currently the only commercially viable long-term CO_2 storage option. These reservoirs are ideal sites because their natural properties have held oils and gases for thousands to millions of years, and they have been thoroughly studied as a result of oil and gas exploration and recovery.

Carbon dioxide can be injected into these reservoirs to enhance oil recovery efforts (i.e., EOR). "This method, called CO_2-EOR, is an attractive option…because it uses pore space that otherwise would remain unavailable and it allows for the recovery and sale of additional oil that would otherwise remain trapped in the reservoir, thus lowering the net cost of CO_2 storage. In North America, CO_2 has been injected into oil reservoirs to increase oil recovery for more than 30 years." However, the application notes that there are no mature oil and gas reservoirs near the proposed facility[5].

5 EPA's 1990 *New Source Review Workshop Manual – Prevention of Significant Deterioration and Nonattainment Area Permitting* discusses technical feasibility analysis as follows:

CCS Energy and Economic Impacts[6]: Studies on the energy and economic impacts for implementing CO_2 capture and storage have been performed. For combined cycle estimates, the DOE report (DOE/NETL-2010/1397) provides a rigorous analysis for a 565 MW_{Gross} natural gas combined cycle plant (NGCC) with and without CO_2 capture. The study considers two large-frame (7 F-equivalent) combustion turbine generators each with a heat recovery steam generator; one steam turbine generator; an amine scrubber and stripper; CO_2 compression, transport, storage, and monitoring; and plant-typical ancillary equipment. Although JOC will utilize only one CT and operate as a cogeneration site, the DOE study's performance impacts and cost ratios are considered for reference. A comparison of performance impacts and cost ratios between NGCC without CO_2 capture and NGCC with CO_2 capture is provided in **Table 10**.

> This step should be should be straightforward for control technologies that are demonstrated – if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible. For control technologies that are not demonstrated in the sense indicated above, the analysis is somewhat more involved.
>
> Two key concepts are important in determining whether an undemonstrated technology is feasible: "availability" and "applicability." As explained in more detail below, a technology is considered "available" if it can be obtained by the applicant through commercial channels or is otherwise available within the common sense meaning of the term. An available technology is "applicable" if it can reasonably be installed and operated on the source type under consideration. A technology that is available and applicable is technically feasible.
>
> A control technique is considered available, within the context presented above, if it has reached the licensing and commercial sales stage of development. A source would not be required to experience extended time delays or resource penalties to allow research to be conducted on a new technique. Neither is it expected that an applicant would be required to experience extended trials to learn how to apply a technology on a totally new and dissimilar source type. Consequently, technologies in the pilot scale testing stages of development would not be considered available for BACT review. An exception would be if the technology were proposed and permitted under the qualifications of an innovative control device consistent with the provisions of 40 CFR 52.21(v) or, where appropriate, the applicable SIP.

The Division of Air Pollution Control reviewed information available from the DOE to determine whether CCS technology has been installed and operated successfully on a similar source. The only U. S. source that we were able to find is Southern Company's Kemper County Energy Facility, which has not commenced operation. SaskPower's Boundary Dam project in Canada began operation in October 2014 but appears to be offline after encountering operational problems with the CCS facility.

Based on the criteria enumerated in EPA's 1990 workshop manual, the Division believes that CCS would not meet either of the criteria outlined above (successful installation and operation or licensing and commercial sales) and could not be considered as technically feasible for the proposed source.
6 If a control technology is not technically feasible, then further analysis of energy and economic impacts is not required. The information in this section was provided by TVA and is included as supporting information.

Table 10: Economic Impact – CO_2 Capture (NGCC)

CO_2 Capture	0%	90%
Gross Power Output (kW)	564,700	511,000
Auxiliary Power Requirement (kW)	9,620	37,430
Capacity Factor (%)	85	85
Net Power Output (kW)	555,080	473,570
Net Plant Efficiency (%)	50.2%	42.8%
Net Plant Heat Rate (Btu[HHV]/kWh)	6,798	7,968
Cost of Electricity ($/MWh)	58.9	85.9

Table 10 indicates that the addition of CCS reduces the plant's efficiency by about 15% and raises electrical generating costs by about 45%. The application states that, these increases can reduce a plant's annual utilization, making CCS economically infeasible at current power market prices.

The application also notes that CT-20's electrical generation will remain simple cycle (i.e., a steam turbine generator will not be used). Simple cycle combustion turbines typically have a net thermal efficiency of 30% and an electrical generating cost of $70/MWh. The addition of CCS would have an adverse effect on generating performance and cost that would exceed the impacts found for a combined cycle plant.

TDEC Review of BACT Analysis

The control technologies identified in the application are consistent with the Division's RBLC review (**Table 11**).

Table 11: Review of RBLC		
Pollutant	**CT, HRSG, Duct Burner**	**Boilers**
General	Tennessee reviewed the RBLC data for process types 11.310 (Commercial/institutional boilers, > 100 MMBtu/hr, natural gas fuel), 15.110 (simple cycle turbines > 25 MW, natural gas fuel), 15.110 (simple cycle turbines > 25 MW, liquid fuel), and 15.290 (combined cycle turbines > 25 MW, liquid fuel) between January 1, 2011, and February, 2016. Other process types (e. g., 15.21) were not searched individually, but appeared in the search results. Any determinations that appeared to be unrelated to a boiler or combustion turbine were not considered in the search. In general, TVA's proposed limits and the RBLC limits were compared if the same units were used.	
Particulate Matter	TVA's proposed limits are 0.005 lb/MMBtu when burning natural gas and 0.015 lb/MMBtu when burning No. 2 oil. There were 59 results for PM in the RBLC, ranging from 0.0019 to 0.0076 lb/MMBtu. All RBLC limits were based on good combustion practices. TVA's proposed controls and limits are consistent with the RBLC results.	TVA's proposed limit is 0.008 lb/MMBtu heat input. There were 87 results for PM in the RBLC, ranging from about 0.002 lb/MMBtu to 0.009 lb/MMBtu. All RBLC limits were based on good combustion practices. TVA's proposed controls are consistent with the RBLC results, and the proposed limits are consistent with to the higher-range RBLC limits. For PM emissions when burning #2 fuel oil, RBLC ID MI-0400 (6/29/2011) specifies a PM emission limit of 0.03 lb/MMBtu when burning diesel fuel.
Carbon Monoxide	TVA's proposed limits are 2 ppmvd when burning natural gas and 10 ppmvd when burning No. 2 oil (both limits are corrected to 15% O_2). There were 40 results for CO in the RBLC, ranging from 1.5 to 29 ppmvd. The RBLC limits were based on fuel selection, good combustion practices, and use of an oxidation catalyst. TVA's proposed controls and limits are consistent with the RBLC results.	TVA's proposed limit is 0.084 lb/MMBtu. There were 50 results for CO in the RBLC . 43 of the RBLC limits were based on good combustion practices and ranged from 0.02 lb/MMBtu to 0.08 lb/MMBtu. These limits were generally higher for boilers that co-fire fuels other than natural gas. Five of the RBLC limits were based on the use of an oxidation catalyst and ranged from 0.0013 lb/MMBtu to 0.1 lb/MMBtu. Two additional results (based on overfire air and burner design/forced-air blower) were comparable to "good combustion practices." TVA's proposed controls and limits are not based on the best control technology (oxidation catalyst) but are adequate based on TVA's evaluation of other impacts and are consistent with the RBLC.

Table 11: Review of RBLC		
Pollutant	**CT, HRSG, Duct Burner**	**Boilers**
Nitrogen Oxides	TVA's proposed limits are 2 ppmvd when burning natural gas and 8 ppmvd when burning No. 2 oil (both limits are corrected to 15% O_2). There were 41 results for NO_X in the RBLC, ranging from 2.5 to 25 ppmvd. The RBLC limits were based on LNB and SCR. TVA's proposed controls and limits are consistent with the RBLC results.	TVA's proposed limit is 0.013 lb/MMBtu. There were 38 results for NO_X in the RBLC, ranging from 0.01 – 0.04 lb/MMBtu. The RBLC limits were based on LNB and SCR. TVA's proposed controls and limits are consistent with the RBLC results.
Carbon Dioxide Equivalent	TVA's proposed limit is 1,800 lb/MWh (12-month moving average). There were 39 results for CO_2e in the RBLC, ranging from 825 – 1,741 lb/MWh. TVA's proposed limit is slightly above the highest RBLC limit. However, the proposed duct burner would not produce electricity when it is operating (presumably, most lb/MWh limits for combined cycle units are based on electricity generation from the duct burners). All RBLC limits are based on good combustion practices.	TVA's proposed limit is 117 lb/MMBtu. There were 15 results for CO_2e in the RBLC. Most of these limits were in tons/year and were not directly compared (the CO_2e limit for RBLC ID OK-0162 is identical to TVA's). All of the CO_2e limits were based on good combustion practices. TVA's proposed controls are consistent with the RBLC.

VI. Ambient Air Quality Impact Analysis

TAPCR 1200-03-09-.01(4)(e) requires the owner or operator of a proposed major stationary source or major modification to demonstrate by source impact analysis that allowable emission increases from the proposed source or modification, in conjunction with all other applicable emissions increases or reductions, would not cause or contribute to air pollution in violation of any Tennessee ambient air quality standard in the source impact area or any applicable maximum allowable increase over the baseline concentration in any area. The owner or operator must submit all data necessary to make these analyses and determinations, including an analysis of the projected air quality impact resulting from general commercial, residential, industrial, and other growth associated with the source or modification.

VI.1 Introduction

This dispersion modeling analysis evaluated emissions of the criteria pollutants regulated under the Prevention of Significant Deterioration (PSD) regulations of 40 CFR 52.21. The criteria pollutant analysis was conducted to insure that the proposed project will not threaten any National Ambient Air Quality Standard (NAAQS) or increments for all criteria pollutants proposed to be emitted above the PSD thresholds of 40 CFR 52.21(b)(23).

VI.2 PROJECT OVERVIEW

Johnsonville Fossil Plant (JOF) is located in New Johnsonville, Tennessee. A site locality map (**Figure 3**) and a topographic map (**Figure 4**) provide details of the location and property boundaries. TVA proposes to operate a cogeneration site (Johnsonville Cogeneration [JOC]) at JOF for steam generation (**Figures 5 and 6**) in lieu of the existing, in-service JOF coal-fired units. The JOC boundary location and modeled sources are shown in **Figures 7 and 8**.

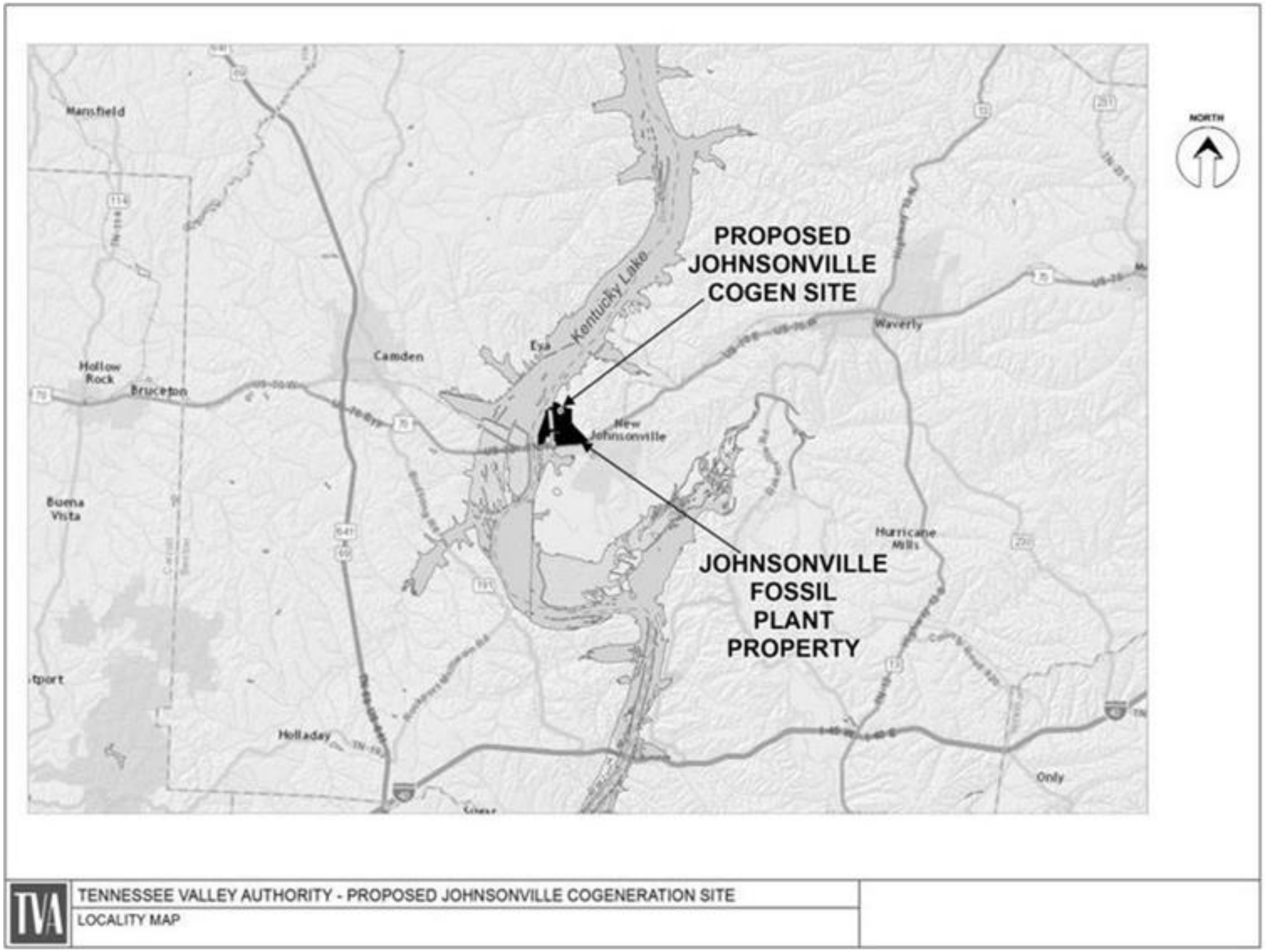

Figure 3: Site Locality Map

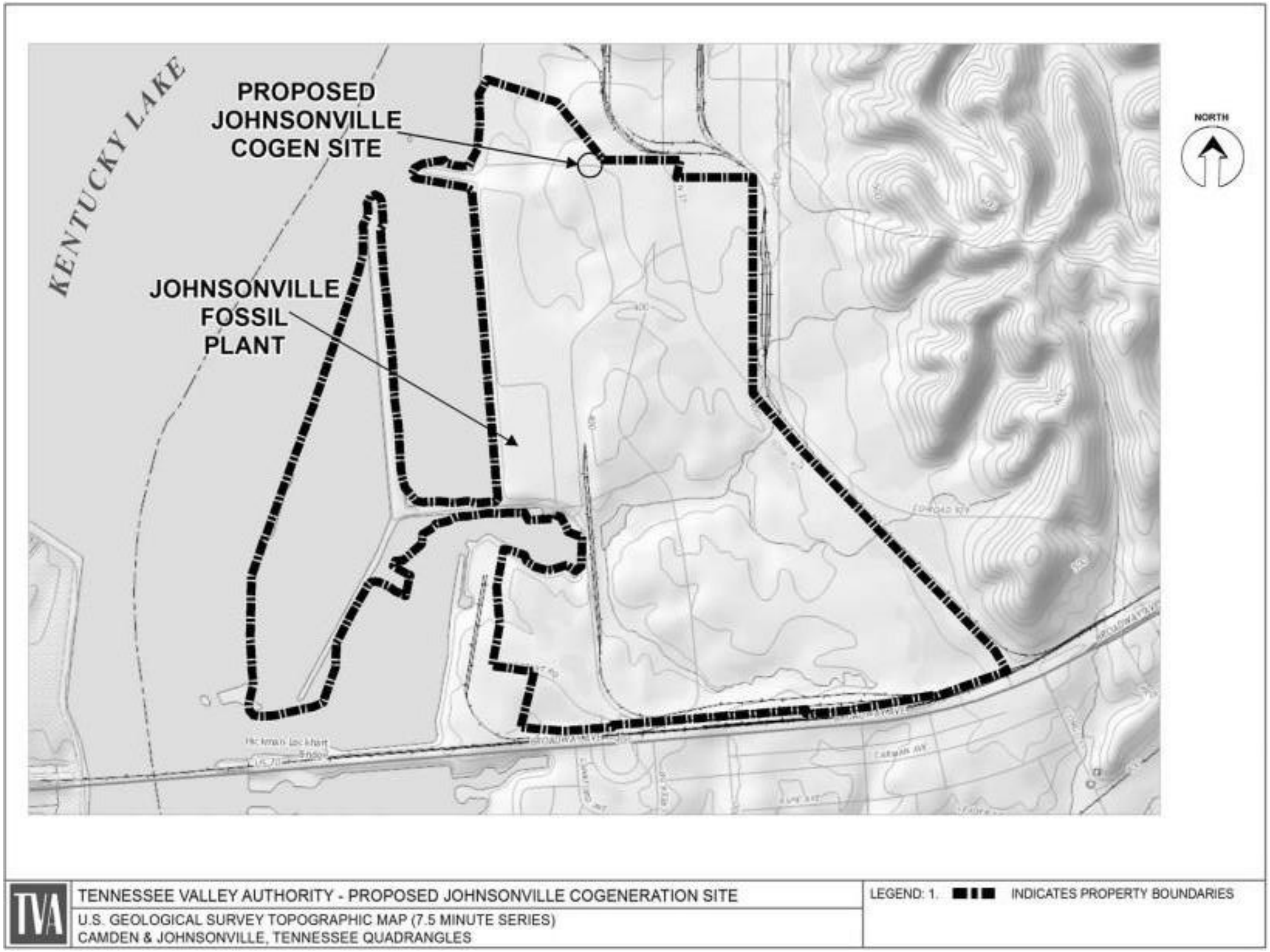

Figure 4: Topographical Map

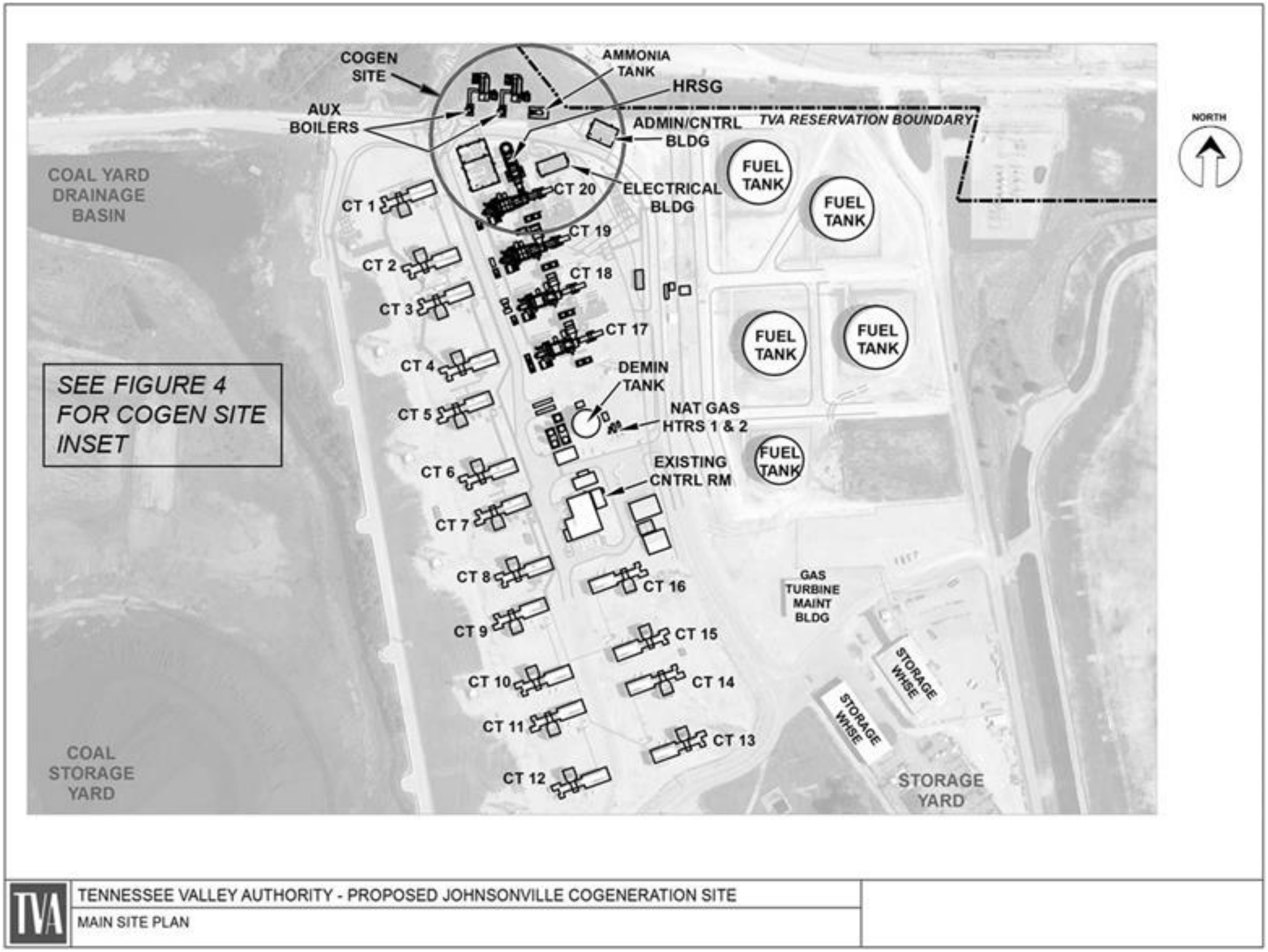

Figure 5: Main Site Plan

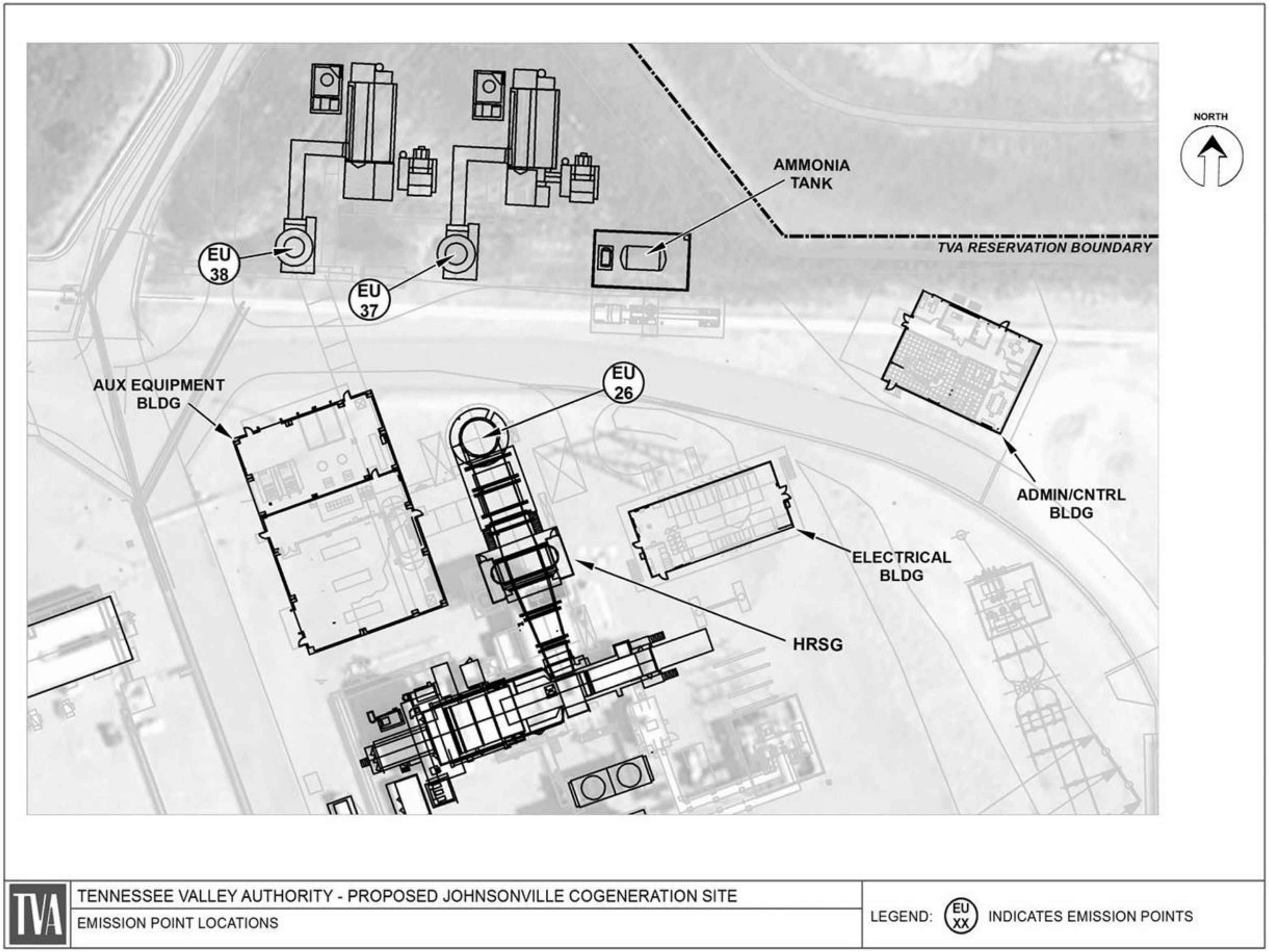

Figure 6: Emission Point Locations

Figure 7: JOC Boundary

Figure 8: JOC Modeled Sources

The cogeneration site will consist of the following:

- One (1) existing, dual-fuel combustion turbine (CT) generator;
- One (1) new heat recovery steam generator (HRSG) with a duct burner, catalytic oxidation, and selective catalytic reduction (SCR);
- Two (2) new natural gas-fired auxiliary boilers with low-NO_x burners, flue-gas recirculation, and SCR.

In addition to these major-equipment systems, the proposed project will include one aqueous ammonia tank and instrumentation and control systems. The proposed construction project will result in increases in emissions of nitrogen oxides (NO_X) and greenhouse gases (GHG) above the PSD thresholds of 40 CFR 52.21(b)(23).

The New Johnsonville, Humphreys County, location is about 70 miles northeast of Jackson, TN. The area is considered a Class II area. The closest Class I areas are the Sipsey National Wilderness Area in central Alabama (187 km), Mammoth Cave National Park in central Kentucky (201km) and Mingo National Wilderness Area in southeastern Missouri (221 km).

Table 12 lists emissions increases from the project compared to the PSD applicability levels for those pollutants emitted at the facility. Emissions increases greater than the applicability level necessitate preliminary modeling analyses for those pollutants:

Table 12: Emission Increases and PSD Applicability Levels

Pollutant	Proposed Increase (tons/year)	Applicability Level (tons/year)
Greenhouse Gases (CO_2e)	616,516	75,000
Nitrogen Oxides (NO_X)	51.2	40
Particulate Matter (PM)	31.5$^{(*)}$	25
Particulate Matter (PM_{10})	31.5$^{(*)}$	15
Particulate Matter ($PM_{2.5}$)	31.5$^{(*)}$	10

$^{(*)}$ Includes filterable and condensable

As required by the PSD regulations, a typical air quality impact assessment may consist of some or all of the following steps:

1. a significant impact area and
2. monitoring *de minimis* analysis for the proposed emission increase.

Also when proposed new impacts are significant:

3. A comprehensive PSD increment consumption analysis,
4. A comprehensive Ambient Air Quality Standards impact analysis, and
5. An additional airshed impact assessment of the effects on Visibility, Soils, Vegetation, Associated Growth, and Nonattainment Areas, as well as Class I area Air Quality Related Values (AQRV's) if applicable.

VI.3 Description of Analysis

Air quality modeling was performed to demonstrate that emissions from the proposed JOC site will not have a significant impact upon the surrounding area. An impact is considered significant if the modeled impacts exceed an applicable Prevention of Significant Deterioration (PSD) Modeling Significant Impact Level (SIL). The SILs for the applicable pollutants associated with this project are presented in **Table 13**. If predicted maximum concentrations exceed a SIL, a full impact analysis is required. This modeling analysis evaluates compliance with applicable PSD increments and the National Ambient Air Quality Standards (NAAQS).

Table 13: Class II PSD Increments and Significant Impact Levels (SILs)					
Pollutant	**Averaging Period**	**Primary NAAQS ($\mu g/m^3$)**	**Secondary NAAQS ($\mu g/m^3$)**	**PSD Class II Increment ($\mu g/m^3$)**	**PSD Significant Impact Level ($\mu g/m^3$)**
CO	1-hour	40,000	40,000	--	2000
	8-hour	10,000	10,000	--	500
$PM_{2.5}$	24-hour	35	35	17	1.2
	Annual	12	12	30	0.3
PM_{10}	24-hour	150	150	--	5
	Annual	--	--	17	1
NO_2	1-hour	188	--	--	7.5
	Annual	100	100	25	1

A total $PM_{2.5}$ NAAQS and PSD increments compliance demonstration is presented in Appendix D of the application. This appendix accounts for contributions from JOC's primary $PM_{2.5}$ concentrations (i.e., direct $PM_{2.5}$ emissions) and from secondary $PM_{2.5}$ concentrations resulting from JOC's $PM_{2.5}$ precursor emissions (NO_X and SO_2). Initial Screening Criteria were also calculated to evaluate potential impacts to Air Quality Related Values (AQRVs) at nearby Class I areas.

VI.4 Local Ambient Impacts

VI.4.1 Modeling Approach

This document summarizes the methodology that was used to evaluate the facility's short range (less than 50 kilometer distance from plant) air quality impacts in Class II areas.

The dispersion modeling described below was performed in accordance with the United States Environmental Protection Agency (EPA) "Guideline on Air Quality Models" (GAQM, contained in 40 CFR Part 51, Appendix W), and direction regulatory guidance provided by Tennessee Department of Environment and Conservation (TDEC). The modeling analysis focuses on demonstrating that the ambient impact of emissions from the proposed JOC project will be less than the PSD Modeling Significance Levels.

VI.4.2 Dispersion Model

Air quality dispersion modeling was performed using the American Meteorological Society/Environmental Protection Agency Regulatory Model (AERMOD) (Version 15181) to obtain estimates of maximum ambient impacts. AERMOD is the preferred regulatory model, in accordance with EPA guidance (40 CFR Part 51, Appendix W, Federal Register Vol. 70, No. 216, November 2005).

For the Class II dispersion modeling, the most current versions of the AERMOD system were used. The options used within the model were the recommended default regulatory options, which include the following:

- Appropriate treatment of calms and use of missing meteorological data routines;
- Inclusion of actual receptor elevations;
- Incorporation of complex / intermediate terrain algorithms;
- Calculations of stack tip downwash;
- Calculation of direction-specific building downwash.

Technical details on AERMOD are presented in "User's Guide for the AMS/EPA Regulatory Model - AERMOD" (EPA-454/B03-001).

VI.4.3 Meteorology

Site specific meteorological data were not available for the JOC site; therefore, surface data collected by the National Weather Service (NWS) at the Nashville International Airport (BNA) in Nashville, Tennessee, were used. Data for the most recent years (2010-2014) were used. Twice-daily soundings for the same time period, also from the BNA airport, were used for the upper air data. The data were processed using the AERMET (Version 15181) meteorological data preprocessor for AERMOD.

Processing of meteorological data with AERMET occurred in three stages. In Stage 1, the hourly surface data and upper air data were extracted from the raw data files and quality assured. In Stage 2, the hourly surface observations and upper air soundings were merged into a single file. In addition, AERMINUTE (Version 15272) was used to process one-minute ASOS wind data for the Nashville NWS site, obtained from The National Climatic Data Center (NCDC), to generate hourly average winds for input into AERMET. Finally, Stage 3 incorporated the boundary layer parameters from the merged NWS data and created the two meteorological files (a surface and upper-air file) which were input meteorology for AERMOD.

When processing meteorological data in AERMET, the surface characteristics of the meteorological site should be used[7]. Calculations of the boundary layer parameters are dependent on the surface characteristics in the vicinity of the modeled facility. The surface characteristics are quantified by the assignment of three variables: surface albedo, Bowen ratio, and surface roughness length. These variables will be set to vary by season using 12 sectors. The surface characteristics were obtained using the USEPA tool, AERSURFACE (Version 13016), which uses land cover data from the U.S. Geological Survey (USGS) National Land Cover Data 1992 archives and look-up tables of surface characteristics that vary by land cover type and season[8].

To address the spatial representativeness of the NWS data for determining surface characteristics and boundary layer parameters, separate AERSURFACE (Version 13016) runs were performed to produce surface characteristics based on a one-kilometer radius centered on the JOC site and another one- kilometer radius centered on the NWS BNA site. AERMET stage 3 was run using both sets (JOC and NWS BNA) of AERSURFACE results to produce two sets of surface and profile input meteorological files for use in the AERMOD analysis.

Tables showing the characterization surface moisture condition assumptions for the JOC site and BNA tower site for each year of meteorology are presented in Appendix E of the application. The surface moisture conditions for the NWS BNA were determined by comparing precipitation for the period of data to be processed to the 30-year climatological record, selecting “wet” conditions if precipitation is in the upper 30th percentile, “dry” conditions if precipitation is in the lower 30th percentile, and “average” conditions if precipitation is in the middle 40th percentile[9]. Both the 30-year precipitation record and the annual precipitation amounts were obtained from the National Oceanic Aviation Administration (NOAA) National Centers for Environmental Information for Nashville, Tennessee. Because annual precipitation amounts at the JOC site were unknown, the surface moisture conditions were determined from analysis of annual precipitation departures (percent of normal) for the JOC location in Humphreys County, Tennessee, as provided from the NWS Advanced Hydrologic Prediction Service (AHPS).

The AERMOD modeling analysis was performed using both sets of meteorological files. The meteorological data set producing the highest modeled concentration was used for the

7 U. S. EPA, 2004: User’s Guide for the AERMOD Meteorological Preprocessor (AERMET). EPA-454/B-03-001. U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

8 U. S. EPA, 2013: AERSURFACE User’s Guide. EPA-454/B-08-001. U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

9 U. S. EPA, 2013: AERSURFACE User’s Guide. EPA-454/B-08-001. U.S. Environmental Protection Agency, Research Triangle Park, NC 27711.

worst case. The AERMET, AERMINUTE, and AERSURFACE input and output files are included on the submitted CD-ROM as part of the PSD application.

VI.4.4 RECEPTORS

The modeling was performed using a Cartesian grid centered on the JOC site and extended out to 20 km in each direction. Nested gridded receptor sets were used for a total of 19,952 receptors. Boundary receptors were also placed along the perimeter of the fenced area of the property and spaced 50 meters apart. These boundary receptors corresponded to a permanent fence surrounding the JOC property.

The nested receptor grids (**Figure 9**) surrounded the facility site with the exception of those falling inside the fenced boundary area, which were removed. Because concentration gradients are most pronounced near a source, the receptor spacing varied with distance from the site with those nearest the site more closely spaced than those further away. The origin of each grid is located in the southwest corner. The initial receptor spacing is outlined in **Table 14**.

Table 14: Receptor Grid Size and Spacing

Receptor Spacing (m)	Grid Size (km)	Grid Origin (km south and west of site)
100	10 × 10	5
250	20 × 20	10
500	40 × 40	20

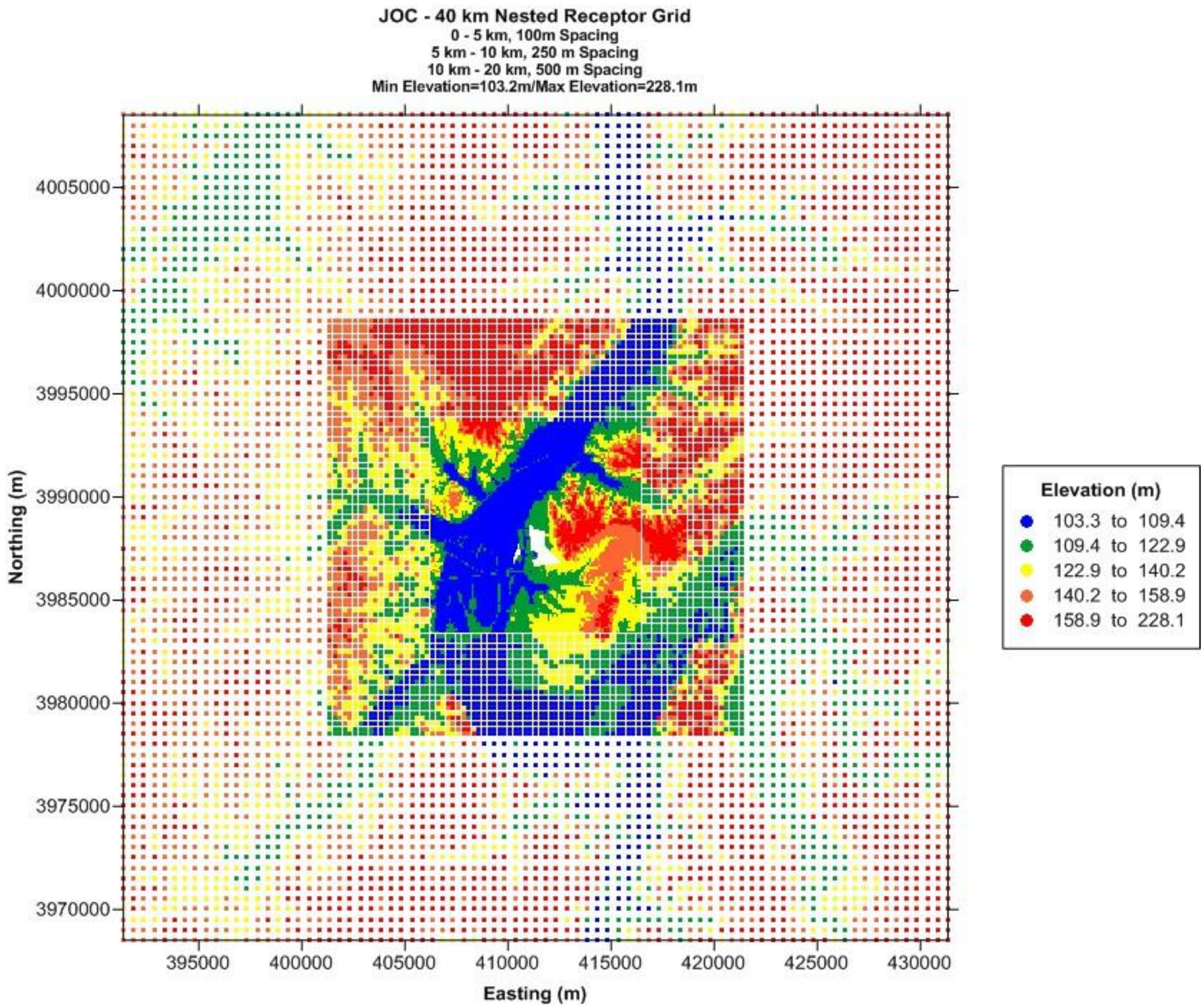

Figure 9: JOC - 40 Km Nested Receptor Grid

If the maximum predicted concentration occurred outside of the 100-meter spaced receptor grid out to five kilometers, an additional round of modeling was performed with a grid of 100-meter spacing to ensure that the maximum was being captured. These additional receptor sets were one kilometer-by-one kilometer, centered on the receptor resulting in the maximum concentration.

Elevations for all receptors were extracted from U.S. Geological Survey (USGS) National Elevation Dataset (NED) files using the AERMAP (Version 11103) module of the AERMOD modeling system. A plot of the receptors is presented, along with the concentration plots, in Appendix G of the application. All AERMAP input and output files are included on the submitted CD-ROM.

VI.4.5 BUILDING DOWNWASH

A Good Engineering Practice stack height analysis was conducted for all stacks and nearby structures associated with the proposed project, using EPA's Building Profile Input Program for PRIME (BPIPPRM, Dated 04274). A structure is considered nearby if it is within 5L of the emissions source where L is the lesser dimension (height or projected width) of the nearby structure. The nearby structures included in the analysis were:

- **One heat recovery steam generator;**
- Twenty structures associated with the existing simple cycle CTs;
- Auxiliary structures associated with ancillary equipment and storage tanks.

The direction-specific effective building widths and heights required by AERMOD were also calculated using EPA's BPIPPRM. The BPIPPRM input stack and building parameters are provided in Tables F-1 and F-2 of Appendix F of the application.

Additional building input parameters (Table F-3) and a figure (Figure F-1) are also provided in Appendix F of the application. Results from BPIPPRM show that the HRSG housing structure is the controlling building. The overall GEP summary table is provided in **Table 15**. The BPIPPRM input and output files are included on the provided CD-ROM.

Table 15: GEP Stack Height Results

Stack	Stack Height (m)	GEP Stack Height (m)	Building Height (m)	Projected Building Width (m)	GEP Eqn. Height (m)
HRSG	45.7	65.00	22.86	17.38	48.89
ABa	60.7	65.00	22.86	11.52	39.51
ABb	60.7	65.00	22.86	15.39	45.30

VI.4.6 SOURCE INFORMATION

The emissions sources included in the air quality modeling are listed in **Table 16**.

Table 16: Emission Sources and Identifiers

Source	Identifier (ID)
CT-20/HRSG Stack	HRSG1
Auxiliary Boiler 1 (AB01) Stack	ABa
Auxiliary Boiler 2 (AB02) Stack	ABb

Physical stack dimensions and locations of each source are presented in **Table 17**. Note that the expected location of the HRSG has changed slightly since the original permit application.

Table 17: Stack Locations and Physical Dimensions					
Stack	**UTM Easting* (m)**	**UTM Northing* (m)**	**Base Elevation (ft, msl)**	**Height (m)**	**Diameter(m)**
HRSG	411344	3988509	118.3	45.7	4.72
ABa	411341	3988533	118.9	60.7	1.98
ABb	411319	3988534	118.9	60.7	1.98
* NAD83 UTM Zone 16.					

VI.4.7 EMISSIONS

Modeling was performed for the CT-20/HRSG operating or the two auxiliary boilers operating. Transitional operation periods (i.e., CT-20/HRSG operating concurrently with the auxiliary boilers) were not considered as they represent atypical / intermittent operations (see Section 2.2.2 of the application outlining auxiliary boilers' function).

Eight model scenarios were developed for both short-term and annual averaging periods. Each CT-20/HRSG scenario simulate No. 2 fuel-oil routine operations and include, when necessary, startup and shutdown to assure the worst-case emissions were modeled. The auxiliary boilers' scenarios simulate routine natural gas-fired operations, which provide worst-case emissions for modeling. All emission estimates used in the modeling are conservatively based on maximum emission rates occurring at low ambient temperatures (0°F or 59°F). Modeling scenario description, flue-gas parameters, and emission rates used for each pollutant are presented in **Tables 17 through 24**.

Table 17: CT-20/HRSG without Auxiliary Boilers Operating Max 1-Hour Average Emissions				
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**NO_X Emissions (g/s)**	**CO Emissions (g/s)**
HRSG (1)	22.4	424	4.86E+00	4.33E+00
ABa	18.2	394	0.00E+00	0.00E+00
ABb	18.2	394	0.00E+00	0.00E+00
(1) Maximum 1-hour average emissions occur at 0°F. For NO_2 modeling, only CT-20/HRSG routine operation emissions are modeled. CT-20/HRSG CO emissions include routine and shutdown operations.				

Table 18: CT-20/HRSG without Auxiliary Boilers Operating Max 8-Hour Average Emissions			
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**CO Emissions (g/s)**
HRSG[1]	16.8	428	4.88E+01
ABa	18.2	394	0.00E+00
ABb	18.2	394	0.00E+00
Note: Maximum 8-hour average emissions occur at 0°F and include CT-20/HRSG startup, routine, and shutdown operations.			

Table 19: CT-20/HRSG without Auxiliary Boilers Operating Max 24-Hour Average Emissions				
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**PM_{10} Emissions (g/s)**	**$PM_{2.5}$ Emissions (g/s)**
HRSG[1]	22.6	428	2.58E+00	2.58E+00
ABa	18.2	394	0.00E+00	0.00E+00
ABb	18.2	394	0.00E+00	0.00E+00
(1) Maximum 24-hour average emissions occur at 0°F include CT-20/HRSG startup, routine, and shutdown operations.				

Table 20: CT-20/HRSG without Auxiliary Boilers Operating Annual Average Emissions					
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**PM_{10} Emissions (g/s)**	**$PM_{2.5}$ Emissions (g/s)**	**NO_X Emissions (g/s)**
HRSG[1]	25.2	428	2.12E+00	2.12E+00	4.37E+00
ABa	18.2	394	0.00E+00	0.00E+00	0.00E+00
ABb	18.2	394	0.00E+00	0.00E+00	0.00E+00
(1) Maximum annual average emissions occur at 59°F include CT-20/HRSG startup, routine, and shutdown operations.					

Table 21: Auxiliary Boilers without CT-20/HRSG Operating Max 1-Hour Average Emissions				
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**NO_X Emissions (g/s)**	**CO Emissions (g/s)**
HRSG[1]	22.4	424	0.00E+00	0.00E+00
ABa	18.2	394	7.37E-01	4.76E+00
ABb	18.2	394	7.37E-01	4.76E+00
(1) Maximum 1-hour average emissions occur at 0°F.				

Table 22: Auxiliary Boilers without CT-20/HRSG Operating Max 8-Hour Average Emissions			
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**CO Emissions (g/s)**
HRSG [(1)]	16.8	428	0.00E+00
ABa	18.2	394	4.76E+00
ABb	18.2	394	4.76E+00
(1) Maximum 8-hour average emissions occur at 0°F.			

Table 23: Auxiliary Boilers without CT-20/HRSG Operating Max 24-Hour Average Emissions				
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**PM_{10} (g/s)**	**$PM_{2.5}$ (g/s)**
HRSG [(1)]	22.6	428	0.00E+00	0.00E+00
ABa	18.2	394	4.54E-01	4.54E-01
ABb	18.2	394	4.54E-01	4.54E-01
(1) Maximum 24-hour average emissions occur at 0°F.				

Table 24: Auxiliary Boilers without CT-20/HRSG Operating Annual Average Emissions					
ID	**Stack Exit Velocity (m/s)**	**Stack Exit Temperature (K)**	**PM_{10} (g/s)**	**$PM_{2.5}$ (g/s)**	**NO_X (g/s)**
HRSG [(1)]	25.2	428	0.00E+00	0.00E+00	0.00E+00
ABa	18.2	394	4.54E-01	4.54E-01	7.37E-01
ABb	18.2	394	4.54E-01	4.54E-01	7.37E-01
(1) Maximum annual average emissions occur at 59°F.					

VI.4.8 MODELING RESULTS

A summary of the maximum modeled impacts for each pollutant is presented in **Table 25**. Modeling CO, PM_{10}, primary $PM_{2.5}$, and annual NO_2 resulted in concentrations below the PSD Modeling Significance Levels.

For the 1-hour NO_2 results, Section 5.2.4 of the EPA's Guideline on Air Quality Models, Appendix W, recommends a three-tiered screening approach to estimating ambient concentrations of NO_2:

- Tier 1 – Assumes complete conversion (100%) of NO to NO_2.
- Tier 2 – Ambient ratio method, which represents the average ambient NO_2/NO_X ratio. Current EPA guidance recommends using a ratio of 0.80.
- Tier 3 – Uses the ozone limiting method and plume molar volume ratio method.

The highest Tier 1, 1-hour average NO_2 impact of 8.33 micrograms per cubic meter (μg/m^3) exceeds the PSD Class II 1-hour average NO_2 SIL of 7.5 μg/m^3; therefore, the Tier 2 approach needed to be applied (NO_2/NO_X ratio of 0.80). The resulting Tier 2, maximum 1-hour average NO_2 impact is 6.67 μg/m^3, which is below the PSD SIL. Consequently, modeling scenarios for all pollutants and averaging periods resulted in concentrations below the PSD Modeling Significance Levels (**Table 25**). A comprehensive summary table of maximum concentrations for all scenarios and meteorological sets is provided in Appendix G of the application. Maximum concentration plots for the worst-case scenarios are also provided in Appendix G.

Table 25: Modeling Results – Estimated Maximum Impacts [1]

Pollutant	Avg. Type: High	Receptor			Meteorology Set [5]	Conc. (μg/m^3)	PSD SIL (μg/m^3)
		East (km)	North (km)	Elev. (ft, msl)			
CO	1-hour	417641	3987964	209.57	OS-Surf	69.10	2000
	8-hour	411441	3989214	118.57	NWS-Surf	59.07	500
$PM_{2.5}$ (primary)	24-hour [2]	411541	3989314	120.74	NWS-Surf	0.90	1.2
	Annual [3]	411541	3989114	120.04	NWS-Surf	0.08	0.3
PM_{10}	24-hour [2]	411541	3989314	120.74	NWS-Surf	1.42	5
	Annual [3]	411541	3989114	120.04	NWS-Surf	0.09	1
NO_2	1-hour (Tier 1) [4]	417641	3987964	209.57	OS-Surf	8.83	7.5
	1-hour (Tier 2) [4]	417641	3987964	209.57	OS-Surf	7.06 [6]	7.5
	Annual [5]	411541	3989114	120.14	NWS-Surf	0.15	1

Notes:
1. Based on 2010-2014 meteorology.
2. Maximum 24-hour primary $PM_{2.5}$ and PM_{10} = highest averaged over 5 years
3. Maximum annual primary $PM_{2.5}$, PM_{10}, and NO_2 = highest annual concentration
4. Maximum 1-hour NO_2 = highest averaged over 5 years.
5. NWS-Surf = meteorological surface characteristics based on National Weather Service (NWS) met tower location; OS-Surf = meteorological surface characteristics based on plant site location (i.e., on-site [OS]).
6. Application of default NO_2/NO_X Tier II ARM, (0.80 x 8.83 μg/m^3 = 7.06 μg/m^3).

For the following emission scenarios, the maximum predicted concentration for 1-hour CO, 8-hour CO, and 1-hour NO_2 occurred at receptors that fell outside of the 100-meter spaced receptor grid:

- 1-hour CO emission for the Auxiliary Boilers without CT-20/HRSG scenario;
- 8-hour CO emission for the Auxiliary Boilers without CT-20/HRSG scenario; and

- 1-hour NO_2 emission for both the CT-20/HRSG without the Auxiliary Boilers scenario and the Auxiliary Boilers without the CT-20/HRSG scenario.

Therefore, an additional round of modeling was performed for those scenarios using a one kilometer-by- one kilometer refined (100-meter spaced) receptor set centered on the maximum concentration receptor to ensure that the highest concentration was being captured. The results of the finer grid modeling showed minor changes to estimated maximum concentrations (**Table 26**). Plots showing the additional fine grids for the worst-case predicted 1-hour CO, 8-hour CO and 1-hour NO_2 are in **Figures 11 and 16**.

Table 26: Additional Modeling Results – Estimated Maximum Impacts [1]

Pollutant	Avg. Type: High	Receptor			Meteorology Set [2]	Conc. (μg/m^3)	PSD SIL (μg/m^3)
		East (km)	North (km)	Elev. (ft, msl)			
CO	1-hour	417591	3988014	209.57	OS-Surf	69.13	2,000
	8-hour	411441	3989214	118.57	NWS-Surf	59.06	500
NO_2	1-hour (Tier 2) [3]	417641	3987964	209.57	OS-Surf	8.83	7.5

Notes:
1. Based on 2010-2014 meteorology.
2. NWS-Surf = meteorological surface characteristics based on National Weather Service (NWS) met tower location; OS-Surf = meteorological surface characteristics based on plant site location (i.e., on-site [OS])
3. Maximum 1-hour NO_2 = highest daily maximum averaged over 5 years

In addition to the modeling results provided in **Table 25**, the analyses of ambient monitoring data and the estimation of secondary $PM_{2.5}$ impacts presented in Appendix D indicate that JOC precursor emissions would not be expected to cause significant levels of secondary $PM_{2.5}$ or contribute to a NAAQS violation.

Concentration isopleths for the worst-case modeled impacts for NO_2, PM_{10}, $PM_{2.5}$, and CO are shown in **Figures 10 through 19**. All results demonstrate that ambient impacts due to emissions from JOC will not be significant.

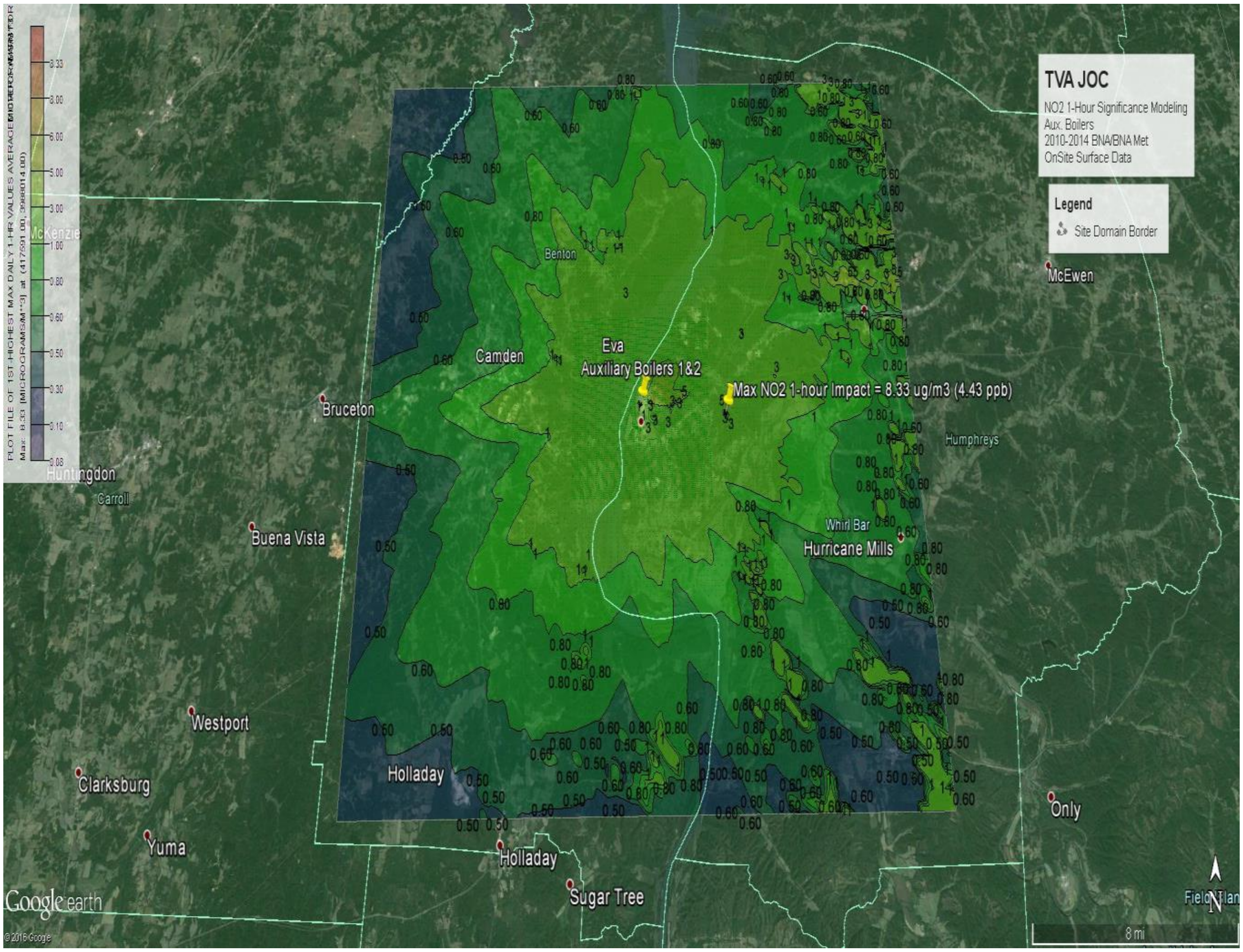

Figure 10: NO_X 1-Hour Max Modeled Results – Auxiliary Boilers (OS-Surf)
(With default Tier II ARM applicability, 0.80 factor, Max Impact = 8.33 x 0.80 = 6.67 µg/m^3; SIL = 7.5 µg/m^3)
(Receptor Location: UTM-E: 417591 Km, UTM-N: 3988014 Km; 250 m Resolution)

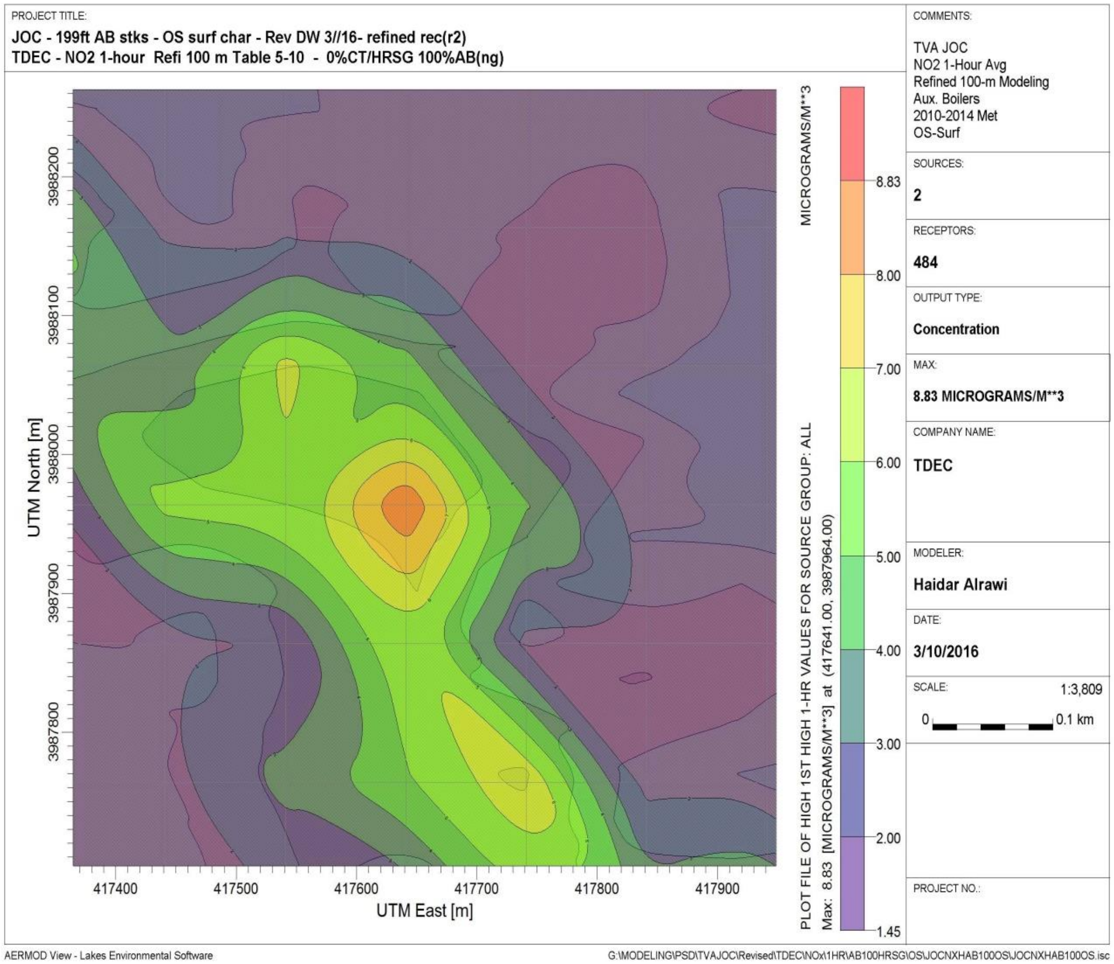

Figure 11: NO_X 1-Hour Max Modeled Results – Auxiliary Boilers (OS-Surf)

(With default Tier II ARM applicability, 0.80 factor, Max Impact = 8.83 x 0.80 = 7.06 µg/m3; SIL = 7.5 µg/m3)

(Receptor Location: UTM-E: 417641 Km, UTM-N: 3987964 Km; 100 m Resolution)

Figure 12: NOx Annual Modeled Results – Auxiliary Boilers (NWS-Surf)
(Max Impact = 0.15 µg/m^3; SIL = 1.0 µg/m^3)
(Receptor Location: UTM-E: 411541 Km, UTM-N: 3989114 Km; 100 m Resolution)

Figure 13: PM$_{10}$ Max 24-Hour Average Modeled Results – CT/HRSG (NWS-Surf)
(Max Impact = 1.42 µg/m^3; SIL = 5.0 µg/m^3)
(Receptor Location: UTM-E: 411541 Km, UTM-N: 3989314 Km; 100 m Resolution)

Figure 14: PM_{10} Max Annual Average Modeled Results – Auxiliary Boilers (NWS-Surf)

(Max Impact = 0.09 µg/m^3; SIL = 1.0 µg/m^3)

(Receptor Location: UTM-E: 411541 Km, UTM-N: 3989114 Km; 100 m Resolution)

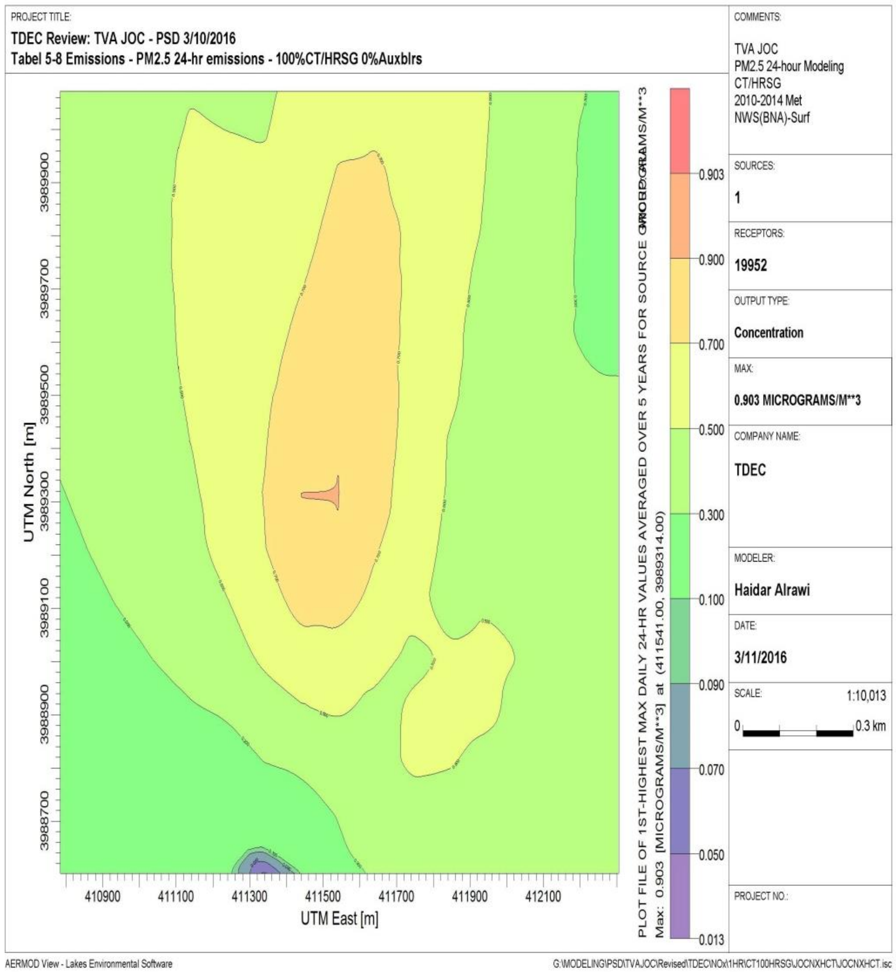

Figure 15: $PM_{2.5}$ (Primary) Max 24-Hour Average Modeled Results – CT/HRSG (NWS-Surf)

(Max Impact = 0.90 μg/m^3; SIL = 1.2 μg/m^3)

(Receptor Location: UTM-E: 411541 Km, UTM-N: 3989314 Km; 100 m Resolution)

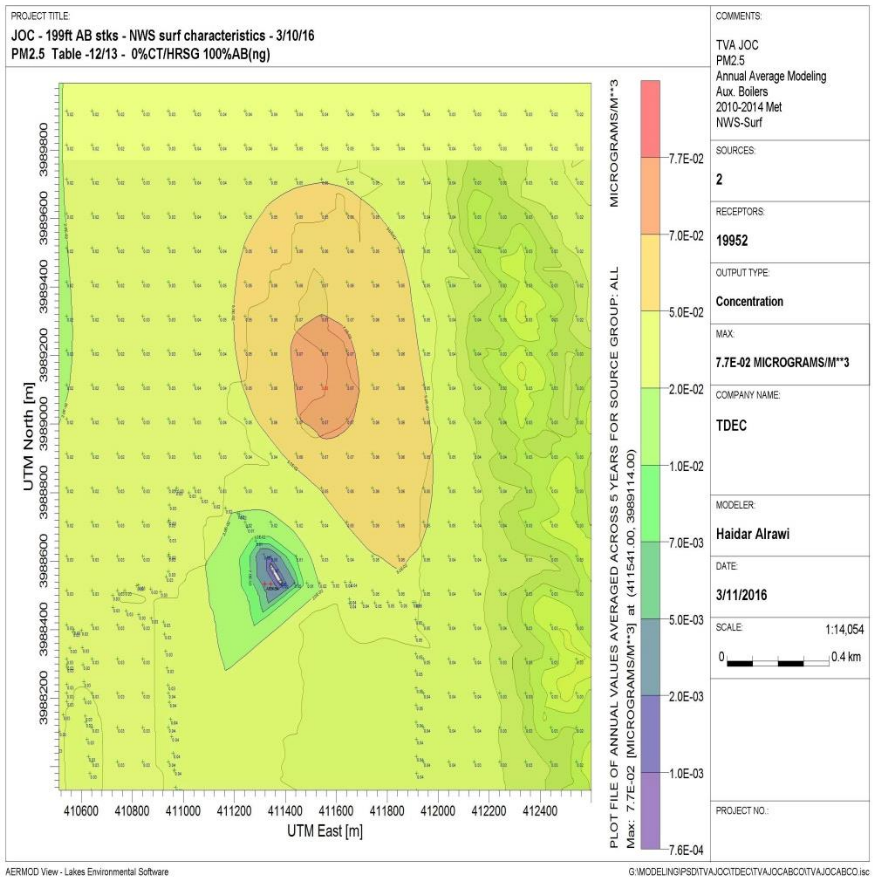

Figure 16: $PM_{2.5}$ (Primary) Max Annual Average Modeled Results – Auxiliary Boilers (NWS-Surf)

(Max Impact = 0.09 µg/m^3; SIL = 1.0 µg/m^3)

(Receptor Location: UTM-E: 411541 Km, UTM-N: 3989114 Km; 100 m Resolution)

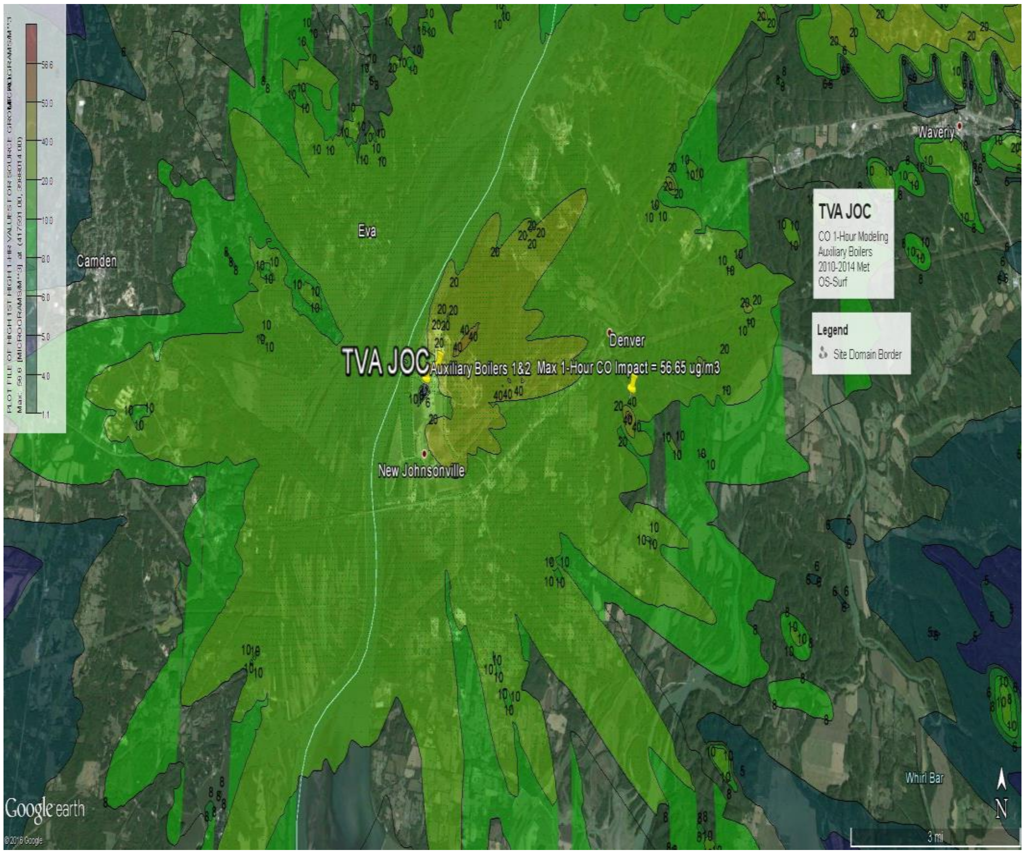

Figure 17: CO Max 1-Hour Average Modeled Results – Auxiliary Boilers (OS-Surf)

(Max Impact = 56.65 μg/m^3; SIL = 2000 μg/m^3)

(Receptor Location: UTM-E: 417591 Km, UTM-N: 3988014 Km; 250 m Resolution)

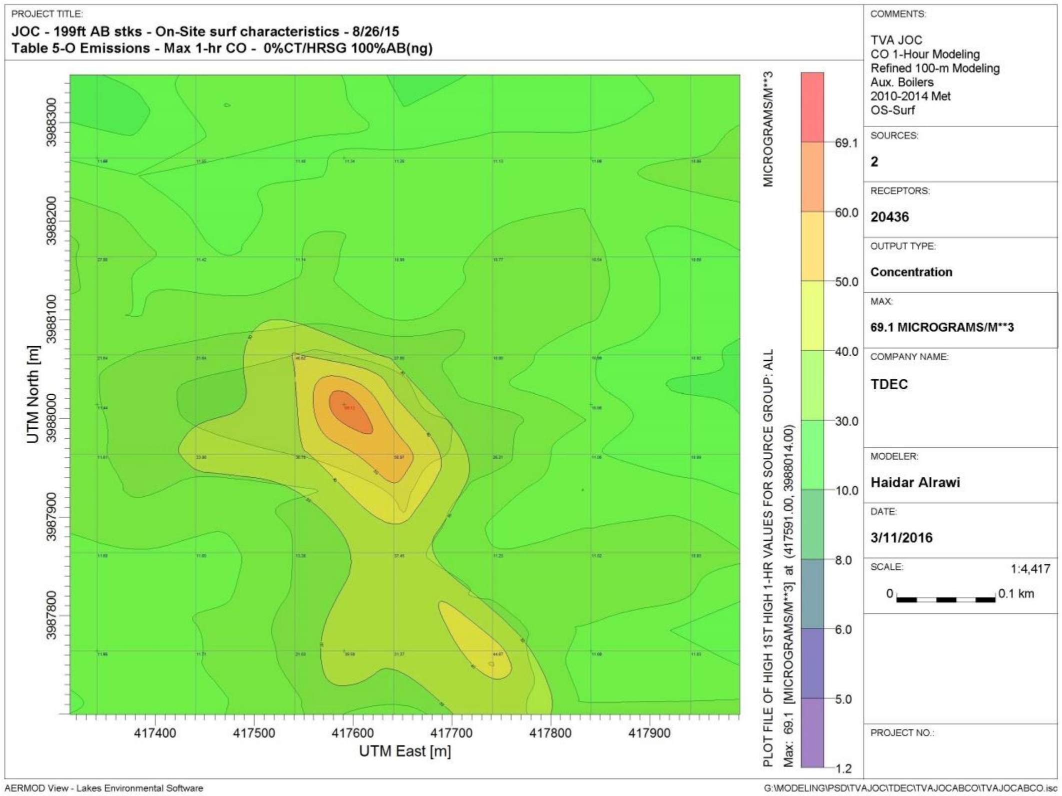

Figure 18: CO Max 1-Hour Average Modeled Results – Auxiliary Boilers (OS-Surf)

(Max Impact = 69.1 μg/m^3; SIL = 2000 μg/m^3)

(Receptor Location: UTM-E: 417641 Km, UTM-N: 3987964 Km; 100 m Resolution)

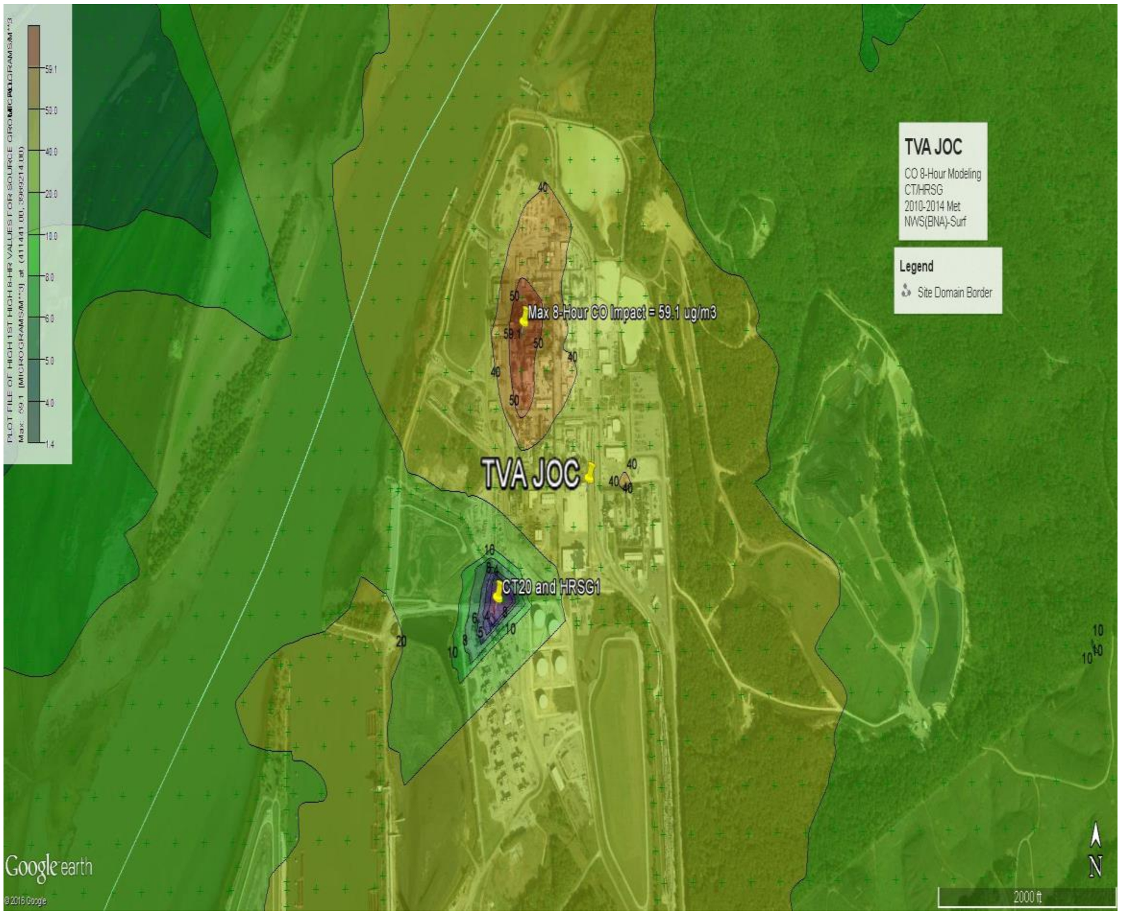

Figure 19: CO Max 8-Hour Average Modeled Results – CT/HRSG (NWS-Surf)
(Max Impact = 59.1 μg/m^3; SIL = 500 μg/m^3)
(Receptor Location: UTM-E: 411441 Km, UTM-N: 3989214 Km; 100 m Resolution)

VI.4.9 IMPACT ON AQRVS IN CLASS I AREAS

Under the Clean Air Act, Federal Land Managers have the responsibility to protect Air Quality Related Values (AQRVs) in Class I areas and to consider whether a proposed major emitting facility will have an adverse impact on these values. Class I AQRVs include visibility impairment, ozone effects on vegetation, and effects of pollutant deposition on soils and surface waters.

Federal Land Managers developed an Initial Screening Criteria, Q/D, to determine if sources greater than 50 kilometers away from a Class I area need to perform any further Class I AQRV impact analyses. Q/D is calculated by summing the annual SO_2, NO_X, PM_{10}, and H_2SO_4 emissions (in tons per year, based on 24 hour maximum allowable emissions and adjusted to reflect 8,760 operating hours per year) and dividing by the distance (in kilometers) to the nearest Class I Area. If the Q/D value is less than or equal to 10, the source is considered to have negligible impacts on AQRVs in the Class I area and no further analyses are needed.

There are three Class I areas within 300 km of JOC: Sipsey Wilderness Area (USFS), Mammoth Cave, and Mingo National Fish and Wildlife Refuge. Annual emissions and distance to the Class I areas used to calculate the Screening Criteria are shown in **Table 27**. The very low Q/D values indicate that proposed JOC project will have a negligible impact on AQRVs in Class I areas, so no further AQRV impact analysis is necessary. Correspondence with the Federal Land Managers and U.S. Forest Service is provided in Appendix H of the application.

Table 27: Values used in Calculating Initial Screening Criteria

	Class I Areas within 300 km		
	Sipsey	**Mammoth Cave**	**Mingo**
SO_2 Emissions (tons/year)	26	26	26
NO_X Emissions (tons/year)	220	220	220
PM_{10} Emissions (tons/year)	117	117	117
H_2SO_4 Emissions (tons/year)	0.09	0.09	0.09
Total Emissions	363	363	363
Distance (km)	187	201	221
Q/D	1.9	1.8	1.6

VII. ADDITIONAL IMPACT ANALYSIS

The PSD regulations require an additional impacts analysis for each pollutant emitted by a source, including the analysis of the effects of emissions on local soils and vegetation. The depth of the analysis performed generally depends on existing air quality, the quantity of air emissions, and the sensitivity of local soils and vegetation. Pursuant to TAPCR 1200-03-09-.01(4)(e)2.(IV), the owner or operator of the proposed major stationary source or major modification must submit an additional impact analysis The owner or operator of the proposed major stationary source or major modification, which addresses the following:

- The impairment to visibility, soils, and vegetation that would occur as a result of the source or modification and the associated general commercial, residential, industrial, and other growth. Vegetation having no significant commercial or recreational value may be excluded from the analysis.

- The air quality impact projected for the area as a result of general commercial, residential, industrial, and other growth associated with the source or modification.

- The Technical Secretary may require monitoring of visibility in any Federal Class I area near the proposed new stationary source or major modification, for such purposes and by such means as the Technical Secretary deems necessary and appropriate.

VII.1 GROWTH ANALYSIS

Air quality impacts projected for the area as a result of general commercial, residential, industrial, and other growth associated with the project are expected to be insignificant. Due to the nature of the project, TVA anticipates negligible emissions growth in the local area. Any resulting emissions growth on the part of TVA electricity customers due to competitive electrical rates would be spread across the entire TVA service region and is expected to have insignificant air quality impacts.

VII.2 SOILS ANALYSIS

Because most air pollutants are ultimately deposited upon the soil, the impact of these pollutants on terrestrial ecosystems is important. Pollutant emissions can impact the soil, ground and surface waters, and plant growth. In many instances, such as metals (e.g., lead, mercury), these pollutants can accumulate in the soil system, or become concentrated via bio magnification through plants and animals. In other instances, these pollutants may cause leaching of soil nutrients (i.e., "acid rain" leaching of soil base cations) or contribute to nutritional imbalances in plant communities (i.e., excessive nitrogen deposition).

The soils in Humphreys County, Tennessee, where the Johnsonville Fossil Plant (JOF) is located, are wholly located within the western part of the physiographic region referred to as the Highland Rim (Soil Survey, Humphreys County, Tennessee, 1946; Soils of Tennessee, 1980. Bulletin 596, University of Tennessee, Knoxville, Tennessee). The western portion of the Highland Rim is highly dissected by a dendritic drainage system.

The county occupies 555 square miles, or 355,200 acres, and three distinct landform groups are identified within the county. The first area includes remnants of the Highland Plateau in the eastern portion of the county. The second distinct area is the dissected region between the plateau and the river bottom, and thirdly, is the westerly portion of the county that is comprised of river bottoms and terraces. The JOF site occupies the latter land class, or the river bottom and terraces, which are nearly level. Soils located in the bottom lands are predominantly loamy or silty and well-drained to moderately well-drained. However, included in this land is clayey and poorly drained soils of the flood plains. The JOF site covers approximately 723 acres. This area includes about 51 acres identified as water in the soil survey and primarily representing the ponds on the JOF island area of the site. The following three soil associations represent the remaining area of JOF.

Paden-Taft-Robertsville: These are very deep soils that occupy the stream terraces. Surface textures are silt loams or silty clay loams, and subsoil textures are dominantly silty clay loams. All have strong acidity and are rather low in natural fertility. Slopes range from 0 to 10 percent. These soils range from moderately-well drained to poorly drained.

Most have features that are generally favorable for crop production with expectations for good yields and moderate risk of crop failure. The Paden and Taft soils have moderate to severe limitations that reduce the choice of plants and/or that require moderate or special conservation practices. The main hazard for crops in the Paden soils is the risk of erosion unless close-growing plant cover is maintained. The main hazard for crop growth with Taft and Robertsville soils is that water in or on the soil interferes with plant growth or cultivation. In addition, the Robertsville soils have limitations that restrict their use mainly to pasture, rangeland, forestland, or wildlife habitat.

Generally, where tree cover has been cleared in this soil association the land is often used for growing corn, cotton, soybeans, hay, and for pasture. However, these areas are often a location for farm homesteads given its upland positioning relative to nearby fertile flood plains and bottoms.

Huntington-Lindside-Wolftever: These are very deep soils that occur in the bottoms or flood plains and on the lower stream terraces and benches. This association also includes the Melvin series of soils. Surface textures are silt loams or silty clay loams, and subsoil textures are dominantly silty clay with some stratified fine sand and gravelly loam composition as well. Slopes range from 0 to 3 percent. These soils range from well drained to poorly drained.

The Huntington soils are fertile and highly productive and very well suited to the production of corn and hay. The Lindside soils are not as well suited to the production of corn and hay. Nevertheless, corn is often chiefly produced in these soils. The position of the Wolftever soils above ordinary overflow enhances their suitability for the production of winter grains, other winter crops, and biennial and perennial crops. The Melvin soils, which ordinarily are too poorly drained for the production of corn and most other crops common to the county, are used chiefly for pasture or left in woods.

All soils in this association have limitations that reduce the choice of plants and/or that require special conservation practices. These soils are subject to frequent flooding; therefore, the main hazard for crop growth in all of these soils is that water in or on the soil interferes with plant growth or cultivation. In addition, chiefly because of the flood hazard, very few farm homesteads are located on soils of this association; nearly all are on the adjoining terraces or uplands.

Ennis-Humphreys: These are the very deep and well drained chief soils in the bottom lands along the creeks originating in the Highland Rim. The Ennis soils occur in the first bottoms and are subject to flooding while the Humphreys soils occur on low terraces, locally called second bottoms or low benches, and are ordinarily above the overflow level except during exceptionally high floods. Some areas of the Lindside and Melvin soils are often included in this association and have been described under previous associations. Slopes range from zero (0) to five (5) percent. Surface and subsoil textures for the Ennis soils are silt loam while Humphreys textures are mostly gravelly silt loam.

The soils in this association, for the most part (excluding any Melvin soils), are physically well suited to the production of crops. However, these soil types have limitations that reduce the choice of plants and/or that require special conservation practices. The main hazard for crop growth in Humphreys soils is the risk of erosion unless close-growing plant cover is maintained. The main hazard for crop growth for Ennis soils is that water in or on the soil interferes with plant growth or cultivation. Corn is often chiefly produced on this soil association. However, cotton, soybeans, tobacco, and hay crops are also suitable.

In addition to the three soil associations found on the JOF site, another soil common to the local area around JOF is the Bodine series, namely, Bodine cherty silt loams. This soil type consists of very deep, somewhat excessively drained, gravelly soils that exist on sharply dissected uplands and hillslopes. Slopes range from five (5) to 60 degrees. Surface textures are cherty silt loams with subsurface very gravelly silt and extremely gravelly silty clay loams. These soils are strongly acid and have low to moderate inherent productivity for crops. In addition, they have very severe limitations that either reduce the choice of plants and/or require special conservation practices or make them entirely unsuitable for cultivation and that restrict their use mainly to pasture, rangeland, forestland, or wildlife habitat. Their stony/gravelly content presents a key limitation for land capabilities for most kinds of field crops.

The direct emissions of criteria pollutants are anticipated to have no measurable impact of the soils in this area due to the very small amounts of pollutants emitted. Findings from the NAPAP report suggest that only ecosystems receiving large amounts of acidifying pollutant loading are subject to harmful effects. The only documented occurrence of this phenomenon is high-elevation coniferous forest in the Eastern United States, where soil base cation leaching and excessive nitrogen deposition are known to occur.

VII.3 VEGETATION IMPACTS

The potential impacts of air emissions from the proposed project were evaluated on the vegetation located in the area of the JOC using U.S. EPA Document EPA-450/2-81-078 "*A Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils, and Animals.*" (US EPA, Dec 1980).

The following sections briefly describe the potential effects of SO2, NO2, O3, CO, and PM10 produced by the facility on the nearby vegetation. The effects of gaseous air pollutants on vegetation may be classified into three rather broad categories: acute, chronic, and long-term. Acute effects are those that result from relatively short (less than one month) exposures to high concentrations of pollutants. Chronic effects occur when organisms are exposed for months or even years to certain threshold levels of pollutants. Long-term effects include abnormal changes in ecosystems and subtle physiological alterations in organisms. Acute and chronic effects are caused by the gaseous pollutant acting directly on the organism; whereas, long-term effects may be indirectly caused by secondary agents such as changes in soil pH.

The potential effects of air emissions on vegetation within the immediate vicinity of the JOC were analyzed by comparison with scientific research examining the effects of pollution on vegetation. Damage to vegetation often results from acute exposure to pollution, but may also occur after prolonged or chronic exposures. Acute exposures are typically manifested by internal physical damage to leaf tissues, while chronic exposures are associated with the inhibition of physiological processes such as photosynthesis, carbon allocation, and stomatal functioning.

Total pollutant impacts from this project are not expected to approach threshold levels for pollutant damage to vegetation in the area. The potential impacted vegetation is mostly residential and forest vegetation. The NO_X maximum modeled 1-hr impact is 7.06 μg/m^3, which is 0.75% of the maximum hourly screening concentration of 940 μg/m^3. The screening concentration level for NO_X is 3,760 μg/m^3 over a 4-hour period as listed in the U.S. EPA document.

Most of the designated vegetation screening levels are equivalent to or less stringent than the NAAQS and/or PSD increments; therefore, satisfaction of NAAQS and PSD increment assures compliance with sensitive vegetation screening levels. **Table 28** characterizes injury threshold concentrations for NO_X for plants native to the Southeastern United States:

Table 28: Injury Threshold Concentrations for NO_X

Common Name	Scientific Name	NO_X
Bryophyte (moss)	Various *Bryophyte sp.*	65 (24 hours)
Birch	*Betula sp.*	120 (chronic)
Common Sunflower	*Helianthus annuals*	375 (chronic)
Alfalfa	*Medicago sativa*	1,000 (5 hours)
Peach	*Prunus persica*	>5,240 (1 hour) >2,100 (3 hours)
Garden Pea	*Pisum sativum*	850 (7 hours)
Cultivated Tobacco	*Nicotiana tabacum*	2,000 (3.5 hours)
Perennial ryegrass	*Lolium perenne*	125 (chronic)
Source: World Health Organization, 2000		

With a modeled 1-hour maximum impact of 7.06 μg/m^3, which is well below the NAAQS (188 μg/m^3), the total pollutant impacts from this project are not expected to approach threshold levels for pollutant damage. The potential impacted vegetation is mostly cropland and pasture, along with some bottomland hardwood forest. Acute levels of pollutants demonstrated to cause plant growth effects are not anticipated to be approached with the added emissions. Furthermore, chronic pollution effects, either direct effects or possible effects from secondary pollutants formed such as ozone, are not anticipated. This is due to the very low increment in pollutant loading that is anticipated to result from the additional emissions and as such, the proposed JOC facility will not have a significant impact or cause injury to nearby vegetation.

VI.3. Post-Construction Monitoring

TAPCR 1200-03-09-.01(4)(e)3 states that the owner or operator of the proposed major stationary source or major modification shall conduct such post-construction monitoring as the Technical Secretary determines is necessary to determine the effect emissions from the stationary source or modification may have, or are having on air quality in any area.

Post-construction monitoring may be required when the NAAQS are threatened or when there are uncertainties in the modeling (e. g., emission inventory) databases. Existing monitors can be considered for collecting post-construction ambient data as long as they have been approved for PSD monitoring purposes. However, the location of the monitors should be checked to ascertain their appropriateness if other new sources or modifications have subsequently occurred, because the new emissions from the more recent projects could alter the location of points of maximum ambient concentrations where ambient measurements need to be made.

Post-construction monitoring is not required, since the air quality impact analysis demonstrates that this project will be below the Significant Impact Levels for all pollutants.

VIII. Conclusions and Conditions of Approval

Projected emissions of PM, CO, NO_X, and CO_2e from the proposed modification exceed the PSD significance levels at maximum operating rate and maximum hours of operation. This major modification is subject to review under the regulations for the Prevention of Significant Deterioration contained in 1200-03-09-.01(4). The proposed control technology satisfies the requirement to install Best Available Control Technology (BACT), as required by the PSD regulations. The BACT requirements are incorporated into the permit to be issued for the proposed modification. The proposed emission increases will not result in ambient impacts that would exceed any National Ambient Air Quality Standards and will not cause or contribute to adverse impacts on Air Quality Related Values in nearby Class I areas.

After review of the information submitted with the PSD application, it is concluded that the proposed modification qualifies for approval to construct, subject to the terms and conditions of the proposed PSD construction permit (Appendix A).

Appendix A – Proposed Construction Permit

Appendix B - Permit Application(s)

Appendix C - Public Notice

Appendix D – Correspondence

STATE OF TENNESSEE
AIR POLLUTION CONTROL BOARD
DEPARTMENT OF ENVIRONMENT AND CONSERVATION
NASHVILLE, TENNESSEE 37243

Permit to Construct or Modify an Air Contaminant Source Issued Pursuant to Tennessee Air Quality Act

Issue Date: ******DRAFT******	Permit Number: 970816F
Expiration Date: ******DRAFT******	

Issued To: Tennessee Valley Authority – Johnsonville Cogeneration	Installation Address: 535 Steam Plant Road New Johnsonville
Installation Description: 43-0011-35: Natural Gas-Fired Combustion Turbine with Heat Recovery Steam Generator (EU-26) 43-0011-36: Natural Gas-Fired Auxiliary Boiler (EU-37) 43-0011-37: Natural Gas-Fired Auxiliary Boiler (EU-38)	Emission Source Reference No. 43-0011-35, 36, 37 PSD

The holder of this permit shall comply with the conditions contained in this permit as well as all applicable provisions of the Tennessee Air Pollution Control Regulations.

CONDITIONS:

1. The applications that were utilized in the preparation of this permit are dated September 17, 2015, and January 26, 2016, and are signed by Clay C. Cherry, Plant Manager for the permitted facility. If this person terminates employment or is reassigned different duties and is no longer the responsible person to represent and bind the facility in environmental permitting affairs, the owner or operator of this air contaminant source shall notify the Technical Secretary of the change. Said notification shall be in writing and submitted within thirty (30) days of the change. The notification shall include the name and title of the new person assigned by the source owner or operator to represent and bind the facility in environmental permitting affairs. All representations, agreement to terms and conditions and covenants made by the former responsible person that were used in the establishment of limiting permit conditions on this permit will continue to be binding on the facility until such time that a revision to this permit is obtained that would change said representations, agreements and covenants.

(conditions continued on next page)

____

TECHNICAL SECRETARY

No Authority is Granted by this Permit to Operate, Construct, or Maintain any Installation in Violation of any Law, Statute, Code, Ordinance, Rule, or Regulation of the State of Tennessee or any of its Political Subdivisions.

NON-TRANSFERABLE **POST AT INSTALLATION ADDRESS**

2. This permit allows the modification of an existing combustion turbine (43-0011-35) and the construction of two natural gas-fired auxiliary boilers (43-0011-36 and 43-0011-37). The modification and new construction are subject to the Prevention of Significant Deterioration (PSD) review provisions of Tennessee Air Pollution Control Regulations (TAPCR) Rule 1200-03-09-.01(4) for significant emissions increases of particulate matter (PM, PM_{10}, and $PM_{2.5}$), carbon monoxide (CO), nitrogen oxides (NO_X), and greenhouse gases (as CO_2e) associated with the proposed project. This source shall operate in accordance with the terms of this permit and the information submitted in the approved permit application. Approval to construct shall not relieve any owner or operator of the responsibility to comply fully with the applicable provisions under this Division 1200-03 and any other requirements under local, State, or Federal law.

   TAPCR 1200-03-09-.01(1)(d) and the application dated September 17, 2015, TAPCR 1200-03-09-.01(4)

3. Approval to construct shall become invalid if construction is not commenced within 18 months after the issue date of this permit, if construction is discontinued for a period of 18 months or more, or if construction is not completed within 18 months of the completion date specified on the construction permit application (December 31, 2018). The Tennessee Air Pollution Control Board may grant an extension to complete construction of the source, provided that adequate justification is presented. An extension shall not exceed 18 months in time.

   TAPCR 1200-03-09-.01(4)(a)4.

4. The following recordkeeping requirements shall apply to this source:

   (a) For all monthly logs, all data, including all required calculations, must be entered in the log no later than thirty (30) days from the end of the month for which the data is required.

   (b) For all weekly logs, all data, including all required calculations, must be entered in the log no later than seven (7) days from the end of the week for which the data is required.

   (c) For all daily logs, all data, including all required calculations, must be entered in the log no later than seven (7) days from the end of the day for which the data is required.

   TAPCR 1200-03-10-.02(2)(a)

5. Visible emissions from this facility shall not exhibit greater than twenty percent (20%) opacity (six-minute average) except for one six-

minute period per one (1) hour of not more than forty (40) percent opacity. Visible emissions from this source shall be determined by EPA Method 9, as published in 40 CFR 60, Appendix A (six-minute average). TAPCR 1200-03-05-.01(1) and 1200-03-05-.03(6)

6. Consistent with the requirements of TAPCR 1200-03-20, due allowance may be made for excess visible emissions that are necessary or unavoidable due to routine startup and shutdown conditions. The permittee shall maintain a continuous, current log of all excess visible emissions showing the time at which such conditions began and ended and that such record shall be available to the Technical Secretary or his representative upon his request. TAPCR 1200-03-05-.02(1)

7. No later than 180 days after initial start-up of this facility, the owner or operator shall furnish the Technical Secretary a written report of the results of an emissions performance test to demonstrate compliance with **Conditions 14 and 26** of this permit. The source test shall be conducted and data reduced in accordance with methodology allowed by the Tennessee Division of Air Pollution Control. At least 30 days prior to the actual test date, the Technical Secretary shall be notified of the official test date and shall be in receipt of a test protocol detailing test methods to be used and any operational parameters to be monitored to assure continual compliance. TAPCR 1200-03-10-.01(1)

8. Upon the malfunction/failure of any emission control device(s) serving these sources, the operation of the process(es) served by the device(s) shall be regulated by Chapter 1200-03-20 of the Tennessee Air Pollution Control Regulations.

9. The permittee shall apply for a Title V Operating Permit for this facility within 360 days of startup of this facility. The application shall be submitted to the West Tennessee Permit Program at the address listed below.

West Tennessee Permit Program Division of Air Pollution Control William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, TN 37243	or	Adobe Portable Document Format (PDF) Copy to: Air.Pollution.Control@tn.gov

TAPCR 1200-03-09-.02(11)(d)1.(i)(II)

10. This permit shall serve as a temporary operating permit from initial start-up of the modified source to the receipt of a Title V Operating Permit, provided that the conditions of this permit and any applicable emission standards are met. TAPCR 1200-03-09-.02(2)

Section	Source-Specific Conditions

II		
43-0011-35	**Combustion Turbine with Heat Recovery Steam Generator (HRSG)**	This emission source consists of one existing duel-fuel combustion turbine (CT) generator (GE Model PG 7121EA) and one new heat recovery steam generator (HRSG) with duct burner. The HRSG will recover waste heat from the CT exhaust and generate steam, which will be piped to an offsite customer. A natural gas-fired duct burner will be used to augment steam production. Duct burner operation is expected to occur about 50% of the year and will not occur during No. 2 fuel oil firing. Catalytic oxidation will be used for control of CO and VOC emissions, and selective catalytic reduction will be used for control of NO_X emissions. 40 CFR 60 Subpart KKKK applies. TVA designated emission unit EU-26.

11. Only natural gas and No. 2 fuel oil, with a sulfur content not to exceed 15 parts per million by weight, shall be used as fuels for this source.

    Compliance Method: Compliance with this condition shall be assured by compliance with **Condition 13** of this permit.

    TAPCR 1200-03-09-.01(1)(d) and the application dated September 17, 2015, TAPCR 1200-03-09-.01(4)

12. The total maximum heat input capacity for this source shall not exceed the following limits on a daily average basis (Table 1).

Table 1: Heat Input Limits	
Unit	**Rated Input Capacity (MMBtu/hr)**
Combustion Turbine	1,019.7 when firing natural gas 1,083.7 when firing No. 2 fuel oil
HRSG Duct Burner	319.3
Heat-input capacity (MMBtu/hr, higher heating value) is for maximum load at 59°F ambient temperature.	

TAPCR 1200-03-09-.01(1)(d), application dated September 17, 2015, TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance with this condition shall be assured by compliance with **Condition 13** of this permit.

13. A daily log of the heat input and fuel usage, which readily shows compliance with **Conditions 11 and 12**, shall be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. This log must be retained for a period of not less than five (5) years.

TAPCR 1200-03-10-.02(2)(a)

14. Particulate matter, carbon monoxide, nitrogen oxides, and carbon dioxide equivalent emitted from this source shall not exceed the limits shown in Table 2. These limits shall represent Best Available Control Technology (BACT) for this emission source.

Table 2: BACT Emission Limits			
Pollutant	**Emission Limit***	**Control Technology**	**Compliance Method**
Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	0.005 lb/MMBtu when firing natural gas	Fuel selection, good combustion design and practices	Comply with **Conditions 7, 11, 12, 13, and 15**
	0.015 lb/MMBtu when firing No. 2 fuel oil		
Carbon Monoxide (CO)	2 ppmvd corrected to 15% O_2 when firing natural gas 30 unit-operating-day moving average	Fuel selection, good combustion design and practices, oxidation catalyst	Comply with **Conditions 7, 11, 12, 13, 15, 17, 18, 19, and 20**
	10 ppmvd corrected to 15% O_2		

	when firing No. 2 fuel oil 15 unit-operating-day moving average		
Nitrogen Oxides (NO_X), as NO_2	2 ppmvd corrected to 15% O_2 when firing natural gas 30 unit-operating-day moving average	Fuel selection, good combustion design and practices, selective catalytic reduction (SCR)	Comply with **Conditions 7, 11, 12, 13, 15, 17, 18, 19, and 20**
	8 ppmvd corrected to 15% O_2 when firing No. 2 fuel oil 15 unit-operating-day moving average		
Carbon Dioxide Equivalent (CO_2e)	1,800 lb/MWh 12-month moving average	Fuel selection, good combustion design and practices	Comply with **Conditions 7, 11, 12, 13, and 15**
* All heat input-based emission limits are based on the high heating value (HHV).			

TAPCR 1200-03-09-.01(4)(j)3.

15. The permittee shall continuously operate any pollution control technology (SCR for NO_X control, oxidation catalyst for CO control) or combustion control (good combustion practice for particulate matter and CO_2e control) at all times when this source is in operation.

TAPCR 1200-03-09-.01(4)(j)3.

16. Volatile organic compounds (VOC) emitted from this source shall not exceed 5.37 tons during any period of twelve consecutive months.

TAPCR 1200-03-07-.07(2)

17. The source shall comply with the applicable requirements of 40 CFR Part 60 Subpart KKKK (Table 3).

Table 3: NSPS Requirements (40 CFR 60 Subpart KKKK)	
Rule Citation	**Requirement**
§30.4305(a)	This subpart applies to each stationary combustion turbine with a heat input at peak load equal to or greater than 10 MMBtu/hr per hour, based on the higher heating value of the fuel, which commenced construction,

Table 3: NSPS Requirements (40 CFR 60 Subpart KKKK)	
Rule Citation	**Requirement**
	modification, or reconstruction after February 18, 2005. Any additional heat input to associated heat recovery steam generators (HRSG) or duct burners should not be included when determining the peak heat input. However, this subpart does apply to emissions from any associated HRSG and duct burners.
§60.4320, §60.4325, Table 1 to Subpart KKKK	NO_X emission limits in Table 1 to Subpart KKKK are not applicable – BACT requirement is more stringent. Comply with §60.4325 when burning mixtures of natural gas and distillate oil.
§60.4330	Comply with SO_2 emission limit of 0.90 lb/MWh gross output or do not burn any fuel which contains total potential sulfur emissions in excess of 0.060 lb SO_2 per MMBtu of heat input. If the turbine simultaneously fires multiple fuels, each fuel must meet this requirement.
§60.4333(a)	Operate and maintain the stationary combustion turbine, air pollution control equipment, and monitoring equipment in a manner consistent with good air pollution control practices for minimizing emissions at all times including during startup, shutdown, and malfunction.
§60.4335(b), §60.4340(b), §60.4345	Install, certify, maintain, and operate a continuous emission monitoring system (CEMS) consisting of a NO_X monitor and a diluent gas (O_2 or CO_2) monitor, to determine the hourly NO_X emission rate in ppm. NO_X CEMS must comply with the specifications of §60.4345.
§60.4350, §60.4380	Use CEMS data as specified in §60.4350 and §60.4380 to identify excess emissions and monitor downtime.
§60.4365	You may elect not to monitor the total sulfur content of the fuel combusted in the turbine, if the fuel is demonstrated not to exceed potential sulfur emissions of 0.060 lb SO_2/MMBtu heat input for units located in continental areas.
§60.4370	Determine the sulfur content of the fuel in accordance with §60.4370

Table 3: NSPS Requirements (40 CFR 60 Subpart KKKK)	
Rule Citation	**Requirement**
§60.4375(a), §60.4395	Submit reports of excess emissions and monitor downtime, in accordance with § 60.7(c). Excess emissions must be reported for all periods of unit operation, including startup, shutdown, and malfunction. All reports required under § 60.7(c) must be postmarked by the 30th day following the end of each six-month period. Reports shall be submitted to: Division of Air Pollution Control Compliance Validation Program William R. Snodgrass Tennessee Tower 312 Rosa L Parks Avenue, 15th Floor Nashville, TN 37243 or Adobe Portable Document Format (PDF) Copy to: Air.Pollution.Control@tn.gov

TAPCR 1200-03-09-.03(8), 40 CFR 60 Subpart KKKK

18. NO_X and CO emissions from this source shall be measured with continuous emissions monitoring systems (CEMS). CO CEMS shall be installed and maintained in accordance with the requirements of 40 CFR 60 Appendix B, Performance Specification 4 or 4A. NO_X CEMS shall be installed and maintained in accordance with 40 CFR 75.

The CO and NO_X CEMS shall be fully operational for at least ninety five percent (95%) of the operating time of the monitored unit during each semiannual period (January 1 through June 30 and July 1 through December 31 of each calendar year). An operational availability of less than this amount may be the basis for declaring a unit in noncompliance with the applicable monitoring requirement, unless the reasons for the failure to maintain this level of availability are accepted by the Division as legitimate malfunctions of the instruments. If any CEMS is inoperative for more than seven consecutive days, the use of a backup monitor may be required.

TAPCR 1200-03-10-.04

19. Quality assurance checks shall be performed on each CEMS in accordance with the requirements of 40 CFR Part 75. The quality assurance checks shall consist of a repetition of the relative accuracy portion of the Performance Specification Test.

Within ninety (90) days of each major modification or major repair of any emissions monitor, diluent monitor, or electronic signal combining system, a repeat of the performance specification test shall be conducted, and a written report of it submitted to the Technical Secretary as proof of the continuous operation of the emissions monitoring system within acceptable limits.

TAPCR 1200-03-10-.02(1)(a)

20. The following information shall be submitted to the Technical Secretary in a semiannual report. Semiannual reports shall cover the 6-month periods from January 1 through June 30 and July 1 to December 31 of each calendar year and shall be submitted within 60 days after the end of each six-month period.

(a) For NO_X, the report shall include emission averages, in the units of the applicable standard (ppmvd corrected to 15% O_2), for each averaging period during operation of the source (24 operating hour average when firing natural gas and 15 operating day average) when firing No. 2 fuel oil.

(b) The report shall include the date and time identifying each period during which the system was inoperative (except for zero and span checks) and the nature of system repairs or adjustments. The Technical Secretary may require proof of system performance whenever system repairs or adjustments have been made.

(c) The report shall include written reports of the quality assurance checks required by **Condition 19.**

(d) When the system has been inoperative, repaired, or adjusted, such information shall be included in the report.

The report shall be submitted to the following address:

West Tennessee Permit Program Division of Air Pollution Control William R. Snodgrass Tennessee Tower 312 Rosa L. Parks Avenue, 15th Floor Nashville, TN 37243	or	Adobe Portable Document Format (PDF) Copy to: Air.Pollution.Control@tn.gov

21. Pursuant to §63.6090(b)(4), existing stationary combustion turbines in all subcategories do not have to meet the requirements of 40 CFR 63 Subparts A and YYYY. No initial notification is necessary for any existing stationary combustion turbine, even if a new or reconstructed turbine in the same category would require an initial notification.

TAPCR 1200-03-09-.03(8), 40 CFR 63 Subpart YYYY

22. The exhaust gases from this source shall be discharged unobstructed vertically upwards to the ambient air from a stack with an exit diameter of 15.5 feet and not less than 150 feet above ground level.

TAPCR 1200-03-09-.01(1)(d), application dated January 26, 2016

43-0011-36	Natural Gas-Fired Auxiliary Boiler (EU-37)	Two 450 MMBtu/hr natural gas-fired auxiliary boilers will provide steam generation during threshold transitional periods and during malfunction events when the CT and HRSG are not able to operate. Each auxiliary boiler will have emissions controlled by low-NO_X burners, flue gas recirculation, and SCR. 40 CFR 60 Subpart Db and 40 CFR 63 Subpart DDDDD apply.
43-0011-37	Natural Gas-Fired Auxiliary Boiler (EU-38)	

23. Only natural gas shall be used as fuel for emission sources 43-0011-36 and 43-0011-37.

Compliance Method: Compliance with this condition shall be assured by compliance with **Condition 26** of this permit.

TAPCR 1200-03-09-.01(1)(d) and the application dated September 17, 2015, TAPCR 1200-03-09-.01(4)

24. The total maximum heat input capacity for emission sources 43-0011-36 and 43-0011-37 shall not exceed the following limits on a daily average basis (Table 4).

Table 4: Heat Input Limits	
Unit	**Rated Input Capacity (MMBtu/hr)**
Natural Gas-Fired Auxiliary Boiler (EU-37)	450
Natural Gas-Fired Auxiliary Boiler (EU-38)	450

TAPCR 1200-03-09-.01(1)(d), application dated September 17, 2015, TAPCR 1200-03-09-.01(4)

Compliance Method: Compliance with this condition shall be assured by compliance with **Condition 25** of this permit.

25. For each auxiliary boiler, a daily log of the heat input and fuel usage, which readily shows compliance with **Conditions 23 and 24**, shall be maintained at the source location and kept available for inspection by the Technical Secretary or his representative. This log must be retained for a period of not less than five (5) years.

TAPCR 1200-03-10-.02(2)(a)

26. Particulate matter, carbon monoxide, nitrogen oxides, and carbon dioxide equivalent emitted from each auxiliary boiler shall not exceed the limits shown in Table 5. These limits shall represent Best Available Control Technology (BACT) for emission sources 43-0011-36 and 43-0011-37.

Table 5: BACT Emission Limits			
Pollutant	**Emission Limit***	**Control Technology**	**Compliance Method**
Total Particulate Matter (PM, PM_{10}, and $PM_{2.5}$)	0.008 lb/MMBtu	Fuel selection, good combustion design and practices	Comply with **Conditions 7, 23, 24, 25, and 27**
Carbon Monoxide (CO)	0.084 lb/MMBtu	Fuel selection, good combustion design and practices	Comply with **Conditions 7, 23, 24, 25, and 27**

Table 5: BACT Emission Limits			
Pollutant	**Emission Limit***	**Control Technology**	**Compliance Method**
Nitrogen Oxides (NO_X)	0.013 lb/MMBtu	Fuel selection, good combustion design and practices, selective catalytic reduction (SCR), low-NO_X burners with flue gas recirculation	Comply with **Conditions 7, 23, 24, 25, and 27**
Carbon Dioxide Equivalent (CO_2e)	117 lb/MMBtu	Fuel selection, efficient design (including insulation to reduce ambient heat loss), good combustion practices, good operating and maintenance practices.	Comply with **Conditions 7, 23, 24, 25, and 27**

* All heat input-based emission limits are based on the high heating value (HHV).

TAPCR 1200-03-09-.01(4)(j)3.

27. The permittee shall continuously operate any pollution control technology (SCR, low-NO_X burners, and flue gas recirculation for NO_X control) or combustion control (good combustion practice for particulate matter, CO, and CO_2e control) at all times when either auxiliary boiler is in operation.

TAPCR 1200-03-09-.01(4)(j)3.

28. Volatile organic compounds (VOC) emitted from each auxiliary boiler shall not exceed 14.2 tons during any period of twelve consecutive months.

TAPCR 1200-03-07-.07(2)

29. This source shall comply with all applicable requirements of 40 CFR Part 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units (Table 6). All required reporting and recordkeeping for the subject unit shall be accomplished in accordance with section §60.49b.

Table 6: Summary of 40 CFR 60 Subpart Db Requirements	
Rule Citation	**Requirement**
§60.44b(l)	No owner or operator of an affected facility that commenced construction after July 9, 1997 shall cause to be discharged into the atmosphere from that affected facility any gases that contain NO_X (expressed as NO_2) in excess of 86 ng/J (0.20 lb/MMBtu) heat input if the affected facility combusts natural gas. Units where more than 10% of total annual output is electrical or mechanical may comply with an optional limit of 270 ng/J (2.1 lb/MWh) gross energy output, based on a 30-day rolling average. Units complying with this limit must demonstrate compliance according to §60.48Da(i) and §§60.49Da(c), (k), through (n).
§60.46b(c)	Compliance with the NO_X emission standards shall be determined through performance testing under §60.46b(e) or (h), as applicable.
§60.48b	Comply with the requirements of §60.48b for NO_X emissions monitoring.
§60.49b(a)	Submit notification of the date of initial startup, as provided by §60.7.
§60.49b(b)	Submit data from the initial performance test and the performance evaluation of the CEMS
§60.49b(c)	The owner or operator of each affected facility who seeks to demonstrate compliance with the NO_X standard through monitoring of steam generating unit operating conditions shall submit a plan that identifies the operating conditions to be monitored and the records to be maintained. This plan shall be submitted to the Administrator for approval within 360 days of the initial startup of the affected facility. If the plan is approved, the owner or operator shall maintain records of predicted NO_X emission rates and the monitored operating conditions identified in the plan.
§60.49b(c)	Maintain records of the amounts of each fuel combusted during each day and calculate the annual capacity factor (12-month rolling average) for the reporting period.
§60.49b(g)	Maintain the following records for each steam generating unit operating day:

Table 6: Summary of 40 CFR 60 Subpart Db Requirements	
Rule Citation	**Requirement**
	(1) Calendar date; (2) Average hourly NO_X emission rates (expressed as NO_2) measured or predicted; (3) 30-day average NO_X emission rates calculated at the end of each steam generating unit operating day; (4) Identification of the steam generating unit operating days when the calculated 30-day average NO_X emission rates are in excess of the NO_X emissions standards, the reasons for such excess emissions, and a description of corrective actions taken; (5) Identification of the steam generating unit operating days for which pollutant data have not been obtained, the reasons for not obtaining sufficient data, and a description of corrective actions taken; (6) Identification of the times when emission data have been excluded from the calculation of average emission rates and the reasons for excluding data; (7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted; (8) Identification of the times when the pollutant concentration exceeded full span of the CEMS; (9) Description of any modifications to the CEMS that could affect the ability of the CEMS to comply with Performance Specification 2 or 3; and (10) Results of daily CEMS drift tests and quarterly accuracy assessments.
§60.49b(i)	Submit reports containing the information recorded under §60.48(g).

Table 6: Summary of 40 CFR 60 Subpart Db Requirements	
Rule Citation	**Requirement**
§60.49b(o)	Maintain all records required under this subpart for 2 years following the date of such record.
§60.49b(v)	The owner or operator of an affected facility may submit electronic reports in lieu of written reports. The format of each quarterly electronic report shall be coordinated with the permitting authority. The electronic report(s) shall be submitted no later than 30 days after the end of the calendar quarter and shall be accompanied by a certification statement from the owner or operator, indicating whether compliance with the applicable emission standards and minimum data requirements of this subpart was achieved during the reporting period. Before submitting reports in the electronic format, the owner or operator shall coordinate with the permitting authority to obtain their agreement to submit reports in this alternative format.
§60.49b(w)	The reporting period for the reports required under this subpart is each six-month period. All reports shall be postmarked by the 30th day following the end of the reporting period.

TAPCR 1200-03-09-.03(8), 40 CFR 60 Subpart Db

30. Each auxiliary boiler shall comply with the applicable requirements of 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (Table 7).

Table 7: Summary of 40 CFR 63 Subpart DDDDD Requirements	
Rule Citation	**Description**
§63.7490(b)	A boiler or process heater is new if you commence construction of the boiler or process heater after June 4, 2010, and you meet the applicability criteria at the time you commence construction.
§63.7495(a)	New sources must comply with Subpart DDDDD by January 31, 2013, or upon startup, whichever is later.
§63.7499(l)	Subcategories of boilers and process heaters: Units designed to burn gas 1 fuels
§63.7500(a)(3)	Operate and maintain any affected source at all times in a manner consistent with safety and good air pollution control practices for minimizing emissions.

Table 7: Summary of 40 CFR 63 Subpart DDDDD Requirements	
Rule Citation	**Description**
§63.7500(e)	Boilers and process heaters in the units designed to burn gas 1 fuels subcategory are not subject to the emission limits in Tables 1 and 2 or 11 through 13 to Subpart DDDDD, or the operating limits in Table 4 to Subpart DDDDD.
§63.7500(f), §63.7505 (a)	Comply with the emission limits, work practice standards, and operating limits in Subpart DDDDD. These limits apply at all times the affected unit is operating, except during periods of startup and shutdown.
§63.7530(f)	Submit the Notification of Compliance Status containing the results of the initial compliance demonstration according to the requirements in § 63.7545(e).
§63.7510(g), §63.7515(d), §63.7540(a)(10)	If your boiler or process heater has a heat input capacity of 10 MMBtu/hr or greater, conduct an annual tune-up of the boiler or process heater to demonstrate continuous compliance. For a new or reconstructed affected source, the first annual tune-up must be no later than 13 months after initial startup of the source. Each subsequent annual tune-up must be no more than 13 months after the previous tune-up. Affected sources must maintain onsite and submit, if requested by the Administrator, an annual report containing the information in §§63.7540(a)(10)(vi)(A) through (C).
§63.7545(a)	Submit to the Administrator all of the notifications in §§ 63.7(b) and (c), 63.8(e), (f)(4) and (6), and 63.9(b) through (h) that apply by the dates specified.
§63.7545(e)	Submit a Notification of Compliance Status according to §63.9(h)(2)(ii).
§63.7550(a), §63.7550(b)	Submit each report in Table 9 to Subpart DDDDD that applies. Unless the Administrator has approved a different schedule for submission of reports, submit each report according to the requirements in §§63.7550(b)(1) through (4). For units that are subject only to a requirement to conduct an annual, biennial, or 5-year tune-up and not subject to emission limits or operating limits, affected sources may submit only an annual, biennial, or 5-year compliance report, as applicable.
§63.7550(c)	If the facility is subject to tune-up requirements, submit a compliance report with the following information: • Company and Facility name and address. • Process unit information, emissions limitations, and operating parameter limitations. • Date of report and beginning and ending dates of the reporting period. • The total operating time during the reporting period. • Include the date of the most recent tune-up for each unit subject to only the requirement to conduct an annual, biennial, or 5-year tune-up. Include the date of the most recent burner inspection if it was not done annually, biennially, or on a 5-year period and was delayed until the next scheduled or unscheduled unit shutdown. • Statement by a responsible official with that official's name, title, and signature, certifying the truth, accuracy, and completeness of the content of the report.
§63.7550(h)	Submit reports according to the procedures specified in §§63.7550(h)(1) through (3).

Table 7: Summary of 40 CFR 63 Subpart DDDDD Requirements	
Rule Citation	**Description**
§§63.7555(a)(1) and (2), §63.7560	Keep the following records: • A copy of each notification and report that you submitted to comply with Subpart DDDDD, including all documentation supporting any Initial Notification or Notification of Compliance Status or semiannual compliance report. • Records of performance tests, fuel analyses, or other compliance demonstrations and performance evaluations as required in §63.10(b)(2)(viii). Records must be in a form suitable and readily available for expeditious review, according to §63.10(b)(1). As specified in § 63.10(b)(1), keep each record for 5 years following the date of each occurrence, measurement, maintenance, corrective action, report, or record. Records must be kept onsite or accessible from onsite for at least 2 years after the date of each occurrence, measurement, maintenance, corrective action, report, or record. Records may be kept offsite for the remaining 3 years.
§63.7565	Part 63 General Provisions apply as indicated in Table 10 to Subpart DDDDD.

TAPCR 1200-03-09-.03(8), 40 CFR 63 Subpart DDDDD

31. The exhaust gases from each boiler shall be discharged unobstructed vertically upwards to the ambient air from a stack with an exit diameter of 6.5 feet, a stack height of not less than 199 feet above ground level, and a stack height of no more than 213 feet above ground level.

TAPCR 1200-03-09-.01(1)(d), application dated January 26, 2016

Section III	Startup Certification

32. The permittee shall certify the start-up date of the air contaminant sources regulated by this permit by submitting

A COPY OF ALL PAGES OF THIS PERMIT,

with the information required in A) and B) of this condition completed, to the Technical Secretary's representatives listed below:

A) DATE OF START-UP: _______ / _____ / ______
month day year

B) Anticipated operating rate: _____ percent of maximum rated capacity

For the purpose of complying with this condition, "start-up" of the air contaminant source shall be the date of the setting in operation of the source for the production of product for sale or use as raw materials or energy production.

The undersigned represents that he/she has the full authority to represent and bind the permittee in environmental permitting affairs. The undersigned further represents that the above provided information is true to the best of his/her knowledge and belief.

Signature		Date
Signer's name (type or print)	Title	Phone (with area code)

Note: This certification is not an application for an operating permit. At a minimum, the appropriate application form(s) must be submitted requesting an operating permit. The application must be submitted in accordance with the requirements of this permit.

The completed certification shall be delivered to the West Tennessee Permit Program at the addresses listed below, no later than thirty (30) days after the air contaminant source is started-up.

West Tennessee Permit Program
Division of Air Pollution Control
William R. Snodgrass Tennessee Tower
312 Rosa L. Parks Avenue, 15th Floor
Nashville, TN 37243

or

Adobe Portable Document Format (PDF)
Copy to: Air.Pollution.Control@tn.gov

(end of conditions)

The permit application gives the location of this source as 36.03° Latitude and -87.98° Longitude.